# THE LEGAL AND REGULATORY TREATMENT OF COGENERATION IN ALBERTA

NIGEL BANKES,* GIORILYN BRUNO,**
AND CAIRNS PRICE***

*Cogeneration is the simultaneous production of electricity and heat from a single fuel source in a process. It allows for a more efficient and effective use of valuable primary energy resources when compared with the independent production of electricity and heat. Cogeneration is therefore attractive to both the private sector and policy-makers because it delivers a range of economic benefits and can be an important strategy in meeting greenhouse gas mitigation targets. This article examines the current legal and regulatory treatment of cogeneration in Alberta in the industrial sector. The authors argue that, given the scale and importance of cogeneration to the province's industrial sector, and to the province generally, it is perhaps time that Alberta developed a clear and coherent policy on cogeneration.*

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* Professor of Law and Chair of Natural Resources Law, University of Calgary and Adjunct Professor of Law, University of Tromsø (ndbankes@ucalgary.ca).
** Research Fellow, Canadian Institute of Resources Law, University of Calgary (gbruno@ucalgary.ca).
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## I. INTRODUCTION

Cogeneration, also known as combined heat and power (CHP), is the simultaneous production of electricity and heat from a single fuel source in a process.[1] Burning fuel always provides heat.[2] Waste heat from electricity generation may be recovered and used for a variety of purposes, including other industrial processes, municipal district energy, space heating and cooling, and water heating.[3]

Cogeneration can be implemented in four main sectors: (1) the public power system; (2) the industrial sector; (3) the commercial-building sector; and (4) the agricultural sector.[4] Many large-scale industrial plants, universities, hospitals, and office buildings have successfully implemented cogeneration technologies for decades. In recent years, these technologies have matured and are becoming increasingly available for smaller-scale applications in residential and commercial facilities.[5]

A key attribute of cogeneration systems is their heat to power ratio (the amount of useful heat or thermal power produced per unit of power).[6] In some cases the system will be designed to produce high quality thermal energy (high pressure and high temperature steam) for particular industrial applications, while in other cases the system will be designed principally to produce electrical energy with warm water as a by-product (80°C) with only limited applications including municipal district energy, space heating and cooling, and water heating.[7] There are two main types of cogeneration — topping cycle and bottoming cycle.[8] In the topping cycle (the most common), fuel is used to generate electricity or mechanical energy at the facility and waste heat from power generation is used to provide useful thermal energy.[9] The less common bottoming cycle type of cogeneration systems produce useful heat for a manufacturing process via fuel combustion or another heat-generating chemical

1 Canadian Industrial Energy Fund End-use Data and Analysis Centre, *Cogeneration Facilities in Canada, 2014* (Burnaby: CIEEDAC, March 2014) at 1, online: CIEEDAC <www2.cieedac.sfu.ca/media/publications/Cogeneration_Report_2014_Final.pdf> [*CIEEDAC 2014 Report*]; Canadian Electricity Association, "Power for the Future," online: <www.powerforthefuture.ca/electricity-411/electricity-fuel-source-technical-papers/cogeneration/>; Manfred Klein, "Cogeneration: A Primer" (Paper delivered at the Combined Heat and Power Workshop, 18 April 2013) at 1 [unpublished].

2 Klein, *ibid* at 1.

3 *Ibid.*

4 See Catherine Strickland & John Nyboer, *Cogeneration Potential in Canada Phase 2* (Burnaby: CIEEDAC, April 2002) at 10–11, 14, online: CIEEDAC <cieedac.sfu.ca/media/publications/cogen potential.pdf>.

5 *CIEEDAC 2014 Report*, *supra* note 1 at 3–7; "Power for the Future," *supra* note 1. District heating and cooling (DHC) in cities and large institutions is one established use of cogeneration (and one widely employed in Europe) in the residential and commercial sectors. District heating can meet low and medium temperature heat demands, such as space heating and hot tap water, by using waste heat from electricity generation to heat water that is transported through insulated pipes. District cooling takes advantage of natural cooling from deep water resources as well as the use of waste heat to cool water via absorption chillers.

6 *CIEEDAC 2014 Report*, *ibid* at 3; Klein, *supra* note 1 at 7; Strickland & Nyboer, *supra* note 4 at 2.

7 *CIEEDAC 2014 Report*, *ibid* at 3–9.

8 Center for Climate and Energy Solutions, "Cogeneration/Combined Heat and Power (CHP)," online: C2ES <www.c2es.org/technology/FactSheet/CogenerationCHP> ["CHP Factsheet"].

9 *Ibid.*

reaction and recover some portion of the exhaust heat to generate electricity.[10] Bottoming cycle CHP applications are most common in process industries, such as glass and steel, which use very high temperature furnaces that would otherwise vent waste heat to the environment.[11]

The specific technologies employed and the efficiencies they achieve will vary, but cogeneration allows a more efficient and effective use of valuable primary energy resources when compared with the independent production of electricity and heat.[12] Therefore, cogeneration is attractive to both the private sector and policy-makers because it delivers a range of economic benefits and can be an important strategy in meeting greenhouse gas mitigation targets.

This article examines the legal and regulatory treatment of cogeneration in Alberta in the industrial sector. Part II describes the economic and environmental benefits of cogeneration. Part III describes the main institutional barriers to the adoption of cogeneration. Part IV discusses the significant expansion of the cogeneration sector in Alberta, particularly in the context of the oil sands industry. Part V provides an overview of the electricity market in Alberta. Part VI focuses on the regulatory treatment of cogeneration projects. In particular, it examines the permitting procedure for the construction and operation of power plants, transmission lines, connections, and distribution systems under the *Hydro and Electric Energy Act*,[13] as well as the concept and implications of an "Industrial System Designation." Part VII focuses on the treatment of cogeneration under Alberta's greenhouse gas management legislation and regulations. Part VIII provides some concluding thoughts. While the article covers the most significant legal and regulatory issues concerning the adoption of cogeneration projects in the industrial sector, it does not address general issues pertaining to the application of environmental assessment legislation or the transaction issues relating to securing an adequate fuel supply for a cogeneration facility.

## II. THE ECONOMIC AND ENVIRONMENTAL BENEFITS OF COGENERATION

"Secure, reliable and affordable energy supplies are fundamental to economic stability and development."[14] Changes in energy demand and supply, the volatility of energy prices, and the erosion of energy security, all pose major challenges for decision-makers.[15] In addition, the threat of climate change has led to increased attention and policy support for constraining greenhouse gas emissions and transitioning to a more sustainable energy path.[16]

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10 *Ibid.*
11 *Ibid.*
12 Cogeneration systems can reach efficiency levels of over 80 percent. A range of technologies can be used to achieve cogeneration, including steam turbines, gas turbines, reciprocating engines, microturbines, fuel cells, and Stirling engines. The system must always include a power generator (either electric power or drive power) and a heat recovery system: see *ibid* at 1–5; Klein, *supra* note 1 at 1; "Power for the Future," *supra* note 1.
13 RSA 2000, c H-16 [*HEEA*].
14 International Energy Agency, *Cogeneration and Renewables: Solutions for a Low-Carbon Energy Future* (Paris: IEA, May 2011) at 6, online: <www.iea.org/publications/freepublications/publication/CoGeneration_RenewablesSolutionsforaLowCarbonEnergyFuture.pdf> [*Low-Carbon Energy Future*].
15 *Ibid* at 6.
16 *Ibid.*

Cogeneration offers five main benefits. First, it is more efficient than traditional forms of power generation and has a lower carbon footprint. The average global efficiency of traditional generators ranges between 35 and 37 percent.[17] The most efficient turbines can bring efficiency close to 45 or 50 percent, but overall they remain significantly less efficient than cogeneration plants.[18] Cogeneration allows 75 to 80 percent of fuel inputs, and "up to 90% in the most efficient plants, to be converted to useful energy."[19] Cogeneration does not, in itself, increase the power supply, but it uses one fuel input to produce two outputs: heat and electricity.[20] By making more efficient use of fuel inputs, cogeneration allows the same level of end-use energy demand to be met with fewer energy inputs. Thus, it reduces energy consumption, greenhouse gas emissions, and other air pollutants such as sulphur dioxide ($SO_2$), mono-nitrogen oxides ($NO_X$), and mercury (Hg).[21] In addition, cogeneration systems can be powered by a variety of both fossil fuels and renewable fuels, including natural gas, coal, oil, biomass, geothermal, and concentrating solar power.[22] In recent years, natural gas has been the predominant fuel for cogeneration systems, but renewables such as biomass and "opportunity fuels" (wastes or by-products from industrial processes, agriculture, or commercial activities) are expected to gain a larger share with growing environmental and energy security concerns. Since renewables bear "obvious low-carbon credentials," technologies that combine renewables and cogeneration enjoy double low-carbon benefits and can achieve powerful low-carbon energy solutions.[23]

Second, cogeneration may provide fuel flexibility and enhance energy security. Some cogeneration technologies can operate with multiple fuel types, which include both renewable and fossil fuels.[24] These cogeneration systems may be adapted over time to respond to changing fuel supply, fuel costs, and electricity price conditions, thus reducing vulnerability to fuel availability and volatility of commodity prices.[25] This ability of cogeneration systems to operate with diverse fuels, and particularly with renewable fuels, makes them part of a balanced and sustainable energy portfolio.[26]

Third, cogeneration reduces reliance on the centralized electric grid and enhances reliability of supply. Cogeneration is a type of distributed or decentralized generation, that is, the power is produced close to where it is used, rather than from a distant centralized source. This approach is inherently more reliable than a small number of very large centralized plants that depend on a large transmission system to transport the power to where it is required.[27] Cogeneration systems can either be connected to the power grid or function as stand-alone systems.[28] When used as stand-alone systems or in "island mode," they are

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17 *Ibid.*
18 *Ibid.*
19 *Ibid.*
20 *Ibid.*
21 "Power for the Future," *supra* note 1; "CHP Factsheet," *supra* note 8.
22 *Low-Carbon Energy Future*, *supra* note 14 at 4.
23 *Ibid* at 13.
24 Northern Alberta Development Council (NADC), *Electric Power Generation Options for Northern Alberta's Municipalities, Organizations and Residents* (Calgary: Forte Business Solutions Ltd, 31 March 2010) at 65, online: Northern Alberta Development Council <www.nadc.gov.ab.ca/ Docs/electric-generation.pdf> [*NADC Report*]; "CHP Factsheet," *supra* note 8.
25 "CHP Factsheet," *ibid.*
26 *Ibid.*
27 Cogen Europe, The European Association for the Promotion of Cogeneration, "What is Cogeneration?," online: <www.cogeneurope.eu/what-is-cogeneration_19.html>.
28 *Ibid.*

able to disconnect from the grid and keep providing electricity and heating to the facilities to which they are directly connected.[29] Thus, these facilities can continue to operate in the event of a failure of the electricity grid or power outage.[30] This may be important for essential services such as hospitals, but also for industrial facilities.[31]

Fourth, cogeneration may reduce the need for transmission and distribution networks as well as energy transmission losses. As a decentralized form of energy supply, cogeneration provides electricity and heat near the point of consumption. Thus, it may avoid or defer investments in new electricity transmission and distribution infrastructure, and relieve congestion constraints on existing infrastructure.[32] Also, by reducing the distance between power plants and consumers, it may reduce energy transmission losses.

Last, cogeneration may provide cost savings for industrial projects that require large amounts of electricity and heat. Some accounts suggest that the efficiency of a combined heat and power system can generate savings of up to 35 to 50 percent for total energy expenditures, and any excess electricity can generally be sold into the power market.[33]

## III. INSTITUTIONAL BARRIERS TO COGENERATION

Despite the multiple benefits of cogeneration, the literature identifies at least four general institutional barriers that impact the potential for cogeneration projects. First, cogeneration is capital-intensive. Building a cogeneration plant requires a greater initial investment than traditional generators.[34] Over the long-term, energy savings and other benefits will justify the initial investment in cogeneration, but some private sector economic decisions may require shorter payback periods.[35] The exposure to fluctuations in the price of natural gas or other

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29 For example, after Superstorm Sandy, cogeneration systems were lauded for their ability to keep operative important facilities such as hospitals: *ibid*.

30 The eastern Canadian ice storm in 1998, the power failure in parts of Ontario and the United States in 2003, and the storms in New York and New Jersey in 2012 left millions of people without power and heat or cooling. Alberta's communities also have occasional power outages: Klein, *supra* note 1 at 5.

31 In August 2003, for example, there was a massive grid failure in the northeastern US and Ontario. Thirty chemical, petrochemical, and oil refining facilities near Sarnia suffered outages costing an estimated $10-20 million per hour: Electricity Consumers Resource Council, "The Economic Impacts of the August 2003 Blackout" (Washington, DC: ELCON, 9 February 2004) at 7, online: <www.elcon.org/Documents/Profiles%20and%20Publications/Economic%20Impacts%20of%20August%202003%20Blackout.pdf>.

32 For example, a report from the Association for Decentralized Energy (ADE) indicates that "[g]enerating energy locally and using it more efficiently has allowed the UK to avoid building 14 new power stations, the equivalent of half the UK's current power generating capacity": see Diarmaid Williams, "Massive incentives to promote demand side investment - ADE," *Cogeneration & On-Site Power Production* (20 January 2015), online: <www.cospp.com/articles/2015/01/massive-incentives-to-promote-demand-side-investment-ade.html>.

33 "What is Cogeneration?," *supra* note 27.

34 For example, the capital cost of a 50 megawatt (MW) gas turbine cogeneration system might be on the order of $45 million, and such a cogeneration system might take 6 to 18 months to construct. A 1 MW reciprocating engine cogeneration system (e.g., for a hospital) might have a capital cost of roughly $1.6 million. The cost of a cogeneration system depends on the level of complexity of features beyond the basic prime mover – such as the heat recovery or emissions monitoring systems (as well as location, labour, and the financial carrying costs during construction). Generally, with the same fuel and configuration, costs for cogeneration systems per kilowatt of capacity decrease as size increases: "CHP Factsheet," *supra* note 8. According to the *NADC Report*, *supra* note 24 at 65, the cost to build a cogeneration facility is in the range of $1.3 million per MW.

35 David Dodge & Duncan Kinney, "Cogeneration: Why your furnace should also be generating electricity" (24 February 2014) *Green Energy Futures* (blog), online: <www.greenenergyfutures.ca/blog/cogeneration-why-your-furnace-should-also-be-generating-electricity> ("If you're under 150 kilowatts you're going to be over a five year payback and if you're over a 150 kilowatt you're going to be a three to five year payback is the rule of thumb").

fuels may also be a disincentive to investing in capital-intensive processes such as cogeneration units as operating costs may vary substantially depending on fuel prices.[36]

Second, siting cogeneration facilities may be challenging. Since steam cannot be transmitted cost-effectively more than four or five kilometers, a cogeneration plant needs to be located near its "thermal host," that is, the user of thermal energy.[37] In addition, facilities will need access to the power grid to be able to sell the excess electricity produced or purchase more electricity from an external supplier as a back up.[38] This may require additional transmission and distribution system lines or upgrades and may be a lengthy and complex process.[39] In some cases the potential cogeneration projects may be located within transmission congestion areas, which limits excess power sales or reduces their value.[40]

Third, environmental regulations that encourage facilities to lower on-site emissions may act as a disincentive to cogeneration. Some firms may decide not to adopt on-site cogeneration to avoid increasing on-site emissions.

Finally, there is a general lack of information and understanding of cogeneration even though it is not a new technology. The need for the developer to spend time and money to develop expertise and quantify the multiple benefits of cogeneration, such as energy savings and system reliability, may be a barrier for many potential cogeneration hosts, since similar information costs are not incurred if power is simply purchased from the grid.[41]

## IV. THE DEVELOPMENT OF COGENERATION IN THE OIL SANDS IN ALBERTA

As of September 2014, Alberta has about 4,500 MW of cogeneration (31 percent of the total installed generation capacity).[42] Sixty-seven percent of Alberta's cogeneration is in the

36 Cogeneration can reduce exposure to fuel prices or raise it, depending on how fuel supply contracts are handled and the available non-cogeneration electricity supply options. Large industrial cogeneration projects may have more leverage to negotiate favourable price conditions: *NADC Report*, *supra* note 24 at 65; Klein, *supra* note 1 at 8; Strickland & Nyboer, *supra* note 4 at 33–34.

37 "Power for the Future," *supra* note 1.

38 Canadian Industrial Energy Fund End-use Data and Analysis Centre, *A Review of Existing Cogeneration Facilities In Canada* (Burnaby: CIEEDAC, March 2012) at 7, online: CIEEDAC <www2.cieedac.sfu.ca/media/publications/Cogeneration_Report_2012_Final.pdf> [*CIEEDAC 2012 Report*]; *Low-Carbon Energy Future*, *supra* note 14 at 10.

39 See Part IV, below for a discussion on the current inadequacy of transmission lines in Alberta's oil sands region; *NADC Report*, *supra* note 24 at 5; "Power for the Future," *supra* note 1; *CIEEDAC 2012 Report*, *ibid* at 7.

40 *NADC Report*, *ibid* at 5. In Alberta, the excess electricity produced in the oil sands is generally offered into the market near the $0/megawatt-hour (MWh) floor to ensure that it will be dispatched: Desiderata Energy Consulting Inc, *2014 Oil Sands Co-generation and Connection Report* (Calgary: Desiderata Energy Consulting Inc, June 2014) at 29, online: Oil Sands Community Alliance <www.oscaalberta.ca/wp-content/uploads/2015/08/2014-Oil-Sands-Cogeneration-Report-FINAL-18-Jun-2014.pdf> [*OSCA 2014*]. For more on this point, see discussion below in Part V.A. The *NADC Report*, *ibid* at 8 suggests that projects may "get entangled in the lengthy processes with load and larger generation connections that can take as long as 3 to 3.5 years from initiation to connection."

41 Klein, *supra* note 1 at 5; Strickland & Nyboer, *supra* note 4 at 33–34.

42 Alberta Energy, "Electricity Facts," online: Alberta Energy <www.energy.alberta.ca/Electricity/681.asp>.

oil sands industry, but it also has municipal, residential, and commercial applications.[43] Cogeneration in the oil sands industry has grown rapidly over the last fifteen years.[44]

Despite its multiple benefits, not all oil sands operators elect to install cogeneration as part of their oil sands facilities. The most recent cogeneration report of the Oil Sands Community Alliance (OSCA)[45] indicates that several factors influence the oil sands operator's decision to build on-site cogeneration, including security of supply and reliability of power from the grid, greenhouse gas costs and regulations, transmission access, charges and capacity, the delivered price of grid power versus the cost of self-generation power, natural gas prices versus power pool prices, and the time and resources required to obtain the necessary regulatory approvals.[46] The last survey (2014) suggested that reliability of power from the grid and the price of alternative power are currently the primary considerations for oil sands operators.[47]

The type of oil sands project also affects the decision to employ on-site cogeneration. Cogeneration makes sense when designed into integrated mining extraction and upgrading oil sands projects, which need both power and heat energy.[48] Cogeneration is also suitable for larger *in situ* thermal projects.[49] Since the heat demand for these projects is much larger than the electricity demand, significant amounts of excess electricity are produced when on-site cogeneration is sized to meet steam loads as opposed to power demand.[50] Therefore, a cogeneration unit sized to meet steam loads will need to be able to export large amounts of electricity off-site if it is to be viable.[51] In this context, transmission access becomes crucial and the inadequacy of transmission connecting the oil sands regions may be a significant obstacle to further uptake of cogeneration.[52]

Traditionally, upgraders were integrated with oil sands mining operations. However, some operators are now locating upgraders away from the oil sands operations due to economic drivers as well as environmental and government requirements.[53] When the extraction and upgrading processes are geographically separated, the benefits of incorporating on-site

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43 Jeremy Moorhouse & Bruce Peachey, "Cogeneration and the Alberta oil sands – cogeneration benefits are maximized with extraction and upgrading integration" *Cogeneration & On-Site Power Production* (1 July 2007), online: <www.cospp.com/articles/print/volume-8/issue-4/features/cogeneration-and-the-alberta-oil-sands-congeneration-benefits-are-maximized-with-extraction-and-upgrading-integration.html>.

44 *Ibid*. For general discussions of the important role of cogeneration in the oil sands sector, see Alberta Electric System Operator, *AESO 2014 Long-term Outlook* (Calgary: AESO, 2014) at 16, online: <www.aeso.ca/downloads/AESO_2014_Long-term_Outlook.pdf>; *OSCA 2014*, *supra* note 40 at 14 (this report has been prepared annually since 1999).

45 *OSCA 2014*, *ibid* at 14.

46 *Ibid* at 12–14.

47 *Ibid* at 14.

48 Moorhouse & Peachey, *supra* note 43.

49 *Ibid*.

50 *OSCA 2014*, *supra* note 40 ("[t]he development of co-generation associated with oil sands operations has gone through several buil cycles with the preferred co-generation sizing switching between a match steam versus match power concept. The current trend seems to be developing and sizing co-generation on a project-by-project basis, with companies making decisions tailored to their development plans" at 27–28). For an argument to the effect that sizing cogeneration to meet the steam demand of *in situ* projects may allow the early retirement of coal generation by providing base load for the integrated system, see GH Doluweera et al, "Evaluating the role of cogeneration for carbon management in Alberta" (2011) 39:12 Energy Policy 7963.

51 Moorhouse & Peachey, *supra* note 43; *OSCA 2014*, *ibid* at 29, 34.

52 Moorhouse & Peachey, *ibid*.

53 *Ibid*.

cogeneration may be less obvious from an individual operator's perspective.[54] Large stand-alone mining and *in situ* projects can still benefit from cogeneration, but for stand-alone upgraders, the decision to incorporate cogeneration mainly depends on (1) the price and availability of fuel supply;[55] (2) the value of the end product;[56] and (3) government incentives.[57]

## V. ALBERTA'S ELECTRICITY MARKET

The excess cogeneration electricity produced in Alberta may be exported to the grid and generate a return.[58] It is therefore important to have a basic understanding of Alberta's electricity market to understand how this output may be integrated into that market.

Alberta began to create a market in electricity in the mid-1990s.[59] Before that time, Alberta's electricity sector was characterized by a small number of dominant players organized as vertically integrated utilities operating in particular geographic service areas: TransAlta, Edmonton Power, and Alberta Power.[60] These utilities (investor-owned with the exception of Edmonton Power) provided service directly to their own customers within their service areas and sold wholesale power to municipal utilities. Most generation was from baseload coal fired power plants with some limited exceptions.[61] Electricity was sold throughout the province on the wholesale or retail level on the basis of a regulated rate

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54 *Ibid.*

55 Regardless of the process used, upgrading requires significant amounts of electricity, natural gas, and water. Natural gas is used for hydrogen production and heat. Exposure to price risk for natural gas may lead upgrader operators to reduce their reliance on gas and thus to gasify available waste products to produce the heat and hydrogen necessary to upgrade the bitumen into synthetic crude oil. Use of gasified waste for these high value purposes may compete with the desire to produce electricity from available upgrader by-products and affect the decision to install cogeneration and cause the operator to buy from the grid: *ibid.*

56 On-site electricity generation is generally produced at the expense of other marketable products such as hydrogen and fuel gas (a by-product of certain upgrading processes that can be cleaned and burned in a gas turbine). The decision to maximize electricity production through cogeneration or maximize hydrogen production depends on the value of the end product. For some upgraders, cogeneration may be a worthy investment in light of the lower costs for electricity, higher thermal efficiency, and higher reliability of supply. On the other hand, other upgraders are able to find clients for their hydrogen production, which may provide a better return than the electricity produced by a cogeneration unit: *ibid.*

57 An individual upgrader operator is exposed to market fluctuations in both the price of bitumen and synthetic crude oil. A company that owns both the upstream bitumen production and the downstream synthetic crude oil production is less vulnerable to fluctuations in the price of bitumen, as its bitumen price will be determined primarily by the production costs. By contrast, an independent upgrader is exposed to both the fluctuating price of synthetic crude oil and bitumen. Such upgraders may be less likely to invest in capital-intensive processes such as cogeneration units unless they have the support of government initiatives: *ibid.*

58 *Ibid.*

59 *Electric Utilities Act*, SA 1995, c E-5.5. The current version of this Act is SA 2003, c E-5.1 [*EUA*].

60 For one account, see Alberta Electric System Operator, *The Path to Transformation: A Case Study of the Formation, Evolution and Performance of the Alberta Electric System Operator* (Calgary: AESO, May 2006), online: <www.aeso.ca/downloads/Path_to_Transformation_email.pdf>. For judicial accounts, see e.g. *ATCO Electric Ltd v Alberta Energy and Utilities Board*, 2004 ABCA 215, 361 AR 1; *ATCO Gas and Pipelines Ltd v Alberta Utilities Commission*, 2014 ABCA 397, 588 AR 134. Other sources include Retail Market Review Committee, *Power for the People* (Edmonton: Alberta Energy, September 2012) at 10–31, Appendix 3, online: <www.energy.alberta.ca/Electricity/pdfs/RMRC report.pdf> (discussing, *inter alia*, the electricity market in Alberta).

61 For example, Medicine Hat owned its own generation (as did Edmonton) as well as a distribution network, and Rural Electrification Associations (REA) first established in the late 1940s, built and operated distribution networks in rural areas on a co-operative basis and with financial support from government. The REAs purchased wholesale power from one of the three dominant utilities. For background, see *Re Central Alberta Rural Electrification Association Limited* (4 July 2012), 2012-181, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2012/2012-181.pdf> [*Re Electrification Association*].

established by the Public Utilities Board (PUB) (then the Alberta Energy and Utilities Board (EUB), now the Alberta Utilities Commission (AUC)) based upon the cost of service principle.[62] All of the transmission in the province was owned by one of the incumbent utilities, or in some cases jointly owned.[63] New facilities, whether in the form of generation or transmission, required the approval of the Energy Resources Conservation Board (later the EUB) as well as being subject to a prudency and used and useful analysis by the PUB before they could enter into the rate base.[64]

The government's decision to introduce competition into Alberta's electricity markets required the province to make structural and institutional changes, including: (1) creation of a power market or pool; (2) encouragement of competition through power purchase agreements (PPAs); (3) continued regulation of transmission and distribution; and (4) the supervision of the market.

## A. THE POWER POOL

The Power Pool is a wholesale market clearing entity. It is operated by Alberta's Independent System Operator (ISO) under the corporate name Alberta Electric System Operator (AESO).[65] All wholesale electrical energy in Alberta must be exchanged through the Power Pool unless exempted.[66] In particular, all electricity generators (or those owning the right to bid generation into the pool under a PPA) must submit a bid into the market for the following seven days on an hourly basis.[67] The bid includes the quantity and price. There can be no physical withholding of capacity.[68] Generators can bid at any price between \$0 and \$999.99/MWh. The AESO then dispatches generation on a real time basis in merit order starting with the lowest bid until generation matches "load" (the demand). The last incremental unit to be dispatched sets the "pool price" or the system marginal price (SMP). In Alberta, generators only receive payment for electricity actually delivered. All generation dispatched receives the pool price.[69]

62 The PUB's jurisdiction over municipally owned utilities was (and still is under the AUC for the distribution business) a complaint-based jurisdiction rather than a full cost of service jurisdiction: see *Municipal Government Act*, RSA 2000, c M-26, s 43. Thus, the PUB set the rates for wholesale service, but the city or local council set the retail rates.

63 One example of joint ownership is discussed in *Alberta Power Ltd v Alberta Public Utilities Board* (1990), 66 DLR (4th) 286 (Alta CA).

64 *Ibid*.

65 The ISO is established by Part 2 of the *EUA*, *supra* note 59, s 7.

66 *Ibid*, s 18(2).

67 The account in the balance of this paragraph draws on a number of sources, principally: Market Surveillance Administrator, *Alberta Wholesale Electricity Market* (Calgary: MSA, 29 September 2010), online: MSA <www.albertamsa.ca/uploads/pdf/Archive/2010/Notice%20and%20Report%20Re%20Alberta%20Wholesale%20Electricity%20Market%20Report%20092910.pdf>; Alberta Electric System Operator, "Determining the Wholesale Market Price for Electricity" (Calgary: AESO, 2015), online: AESO <www.aeso.ca/downloads/Wholesale_Market_Price_Fact_Sheet_020311.pdf>; Market Surveillance Administrator, *State of the Market Report 2012: An Assessment of the Structure, Conduct, and Performance of Alberta's wholesale electricity market* (Calgary: MSA, 10 December 2012), online: MSA <www.albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Final%20Report%2020130104.pdf>.

68 *Fair, Efficient and Open Competition Regulation*, Alta Reg 159/2009, s 2(f).

69 Alberta is an "energy only market" as opposed to a "capacity market." In a capacity market, a generator is also paid for making capacity available regardless of whether electricity is produced. A capacity market may offer some greater assurance to a new entrant that it will be able to recover some or all of its investments: *Power for the People*, *supra* note 60 at 233.

Excess cogeneration electricity produced in Alberta is exported to the grid.[70] The OSCA cogeneration report categorizes exports to the grid as "Surplus Net Exports" or "Merchant Net Exports." Surplus Net Exports typically operate regardless of electricity prices and are associated with cogenerators that are sized to meet on-site steam requirements, and produce excess electricity as a by-product.[71] This surplus is generally bid near the $0/MWh floor to ensure that it will be dispatched.[72] In the oil sands context, this ensures steam or hot water required for the oil sands process is available, with no changes to on-site operations in response to hourly spot market electricity prices.[73] Currently, the majority of cogeneration net exports from the oil sands are Surplus Net Exports or non-price responsive.[74] By contrast, Merchant Net Exports refers to cogenerators who are able to respond to price movements in the power market without detrimentally impacting steam supplies or production.[75]

## B. STATUTORY POWER PURCHASE AGREEMENTS AND ENHANCED COMPETITION

In order to transition from regulation to markets, the government had to take proactive measures to increase competition in the generation sector.[76] This goal was achieved through the creation of long-term statutory PPAs. Under the PPAs, the purchaser of the output has the ability to determine bids into the power pool. The owner of the facility is compensated on a traditional cost of service basis (that is, the owner is held harmless from the results of deregulation).[77] The purchaser under the PPA bears the market risk that the pool price will be below or above the cost of service. The PPAs expire over time, with the right to bid reverting to the owner of the facility at the expiration of the PPA to the extent that the facility still has a useful life.[78] It is anticipated that by then, new entrants, including cogenerators, will have entered the market in sufficient numbers and control enough generation to dilute the market share of the former incumbents.

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70 Moorhouse & Peachey, *supra* note 43.

71 *OSCA 2014*, *supra* note 40 at 29.

72 *Ibid*. It is for this reason that it is possible to think of cogeneration as having the potential to displace base load coal generation: see Doluweera et al, *supra* note 50 at 7964.

73 *OSCA 2014*, *ibid*.

74 *Ibid*.

75 *Ibid*.

76 The bulk of generation was owned by the three incumbent integrated utilities who were individually and collectively able to exercise market power. New players might enter the market over time in response to increasing demand, but it was necessary to take some immediate steps as well. Even though the government might have passed legislation requiring forced divestiture, it preferred the less invasive technique of unbundling the ability to bid power into the pool from the ownership of the facility: see generally the referecence cited in note 60, *supra*.

77 For discussion, see Terra Nicolay, "Regulation by Any Other Name: Electricity Deregulation in Alberta and the Power Purchase Arrangements" (2011) 29:1 J Energy & Nat Resources L 45.

78 For a table listing thermal PPAs with capacity and expiry dates, see Market Surveillance Administrator, *Alberta Wholesale Market: A description of basic structural features undertaken as part of the 2012 State of the Market Report* (Calgary: MSA, 30 August 2012) at 4, Table 3.1, online: <www.albertasma.ca/uploads/pdf/Archive/2012/SOTM%20Basic%20Structure%20083012.pdf>.

### C. TRANSMISSION, THE ROLE OF THE ISO, AND THE COSTS BORNE BY GENERATION

While the government decided to introduce competition in the electricity generation and retail sectors, the transmission and distribution functions remain a natural monopoly.[79] In response to that reality, the government elected to leave transmission under the ownership of the incumbent utilities, while giving the ISO (AESO) the responsibility for the coordinated planning and use of transmission facilities.[80] The AESO (supervised to some degree by the AUC) is also responsible for commissioning new transmission. Chiefly, the AESO identifies a need for transmission based on its long-range plans[81] and in response prepares a Needs Identification Document (NID) to meet grid expansion needs in a particular area for consideration by the AUC.[82] Once approved by the AUC, the AESO either requires a party (usually the incumbent transmission facility owner in the area) to build and commission the new transmission facility, or puts the project out for tender.[83]

The owner of a generation facility, including a cogeneration facility, will generally require system access service to the transmission system through the ISO. The ISO "is the sole provider of system access service on the transmission system"[84] and must provide such access "in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so."[85] Both the AUC and the courts have interpreteted this as a duty to provide non-discriminatory access to the transmission system in accordance with the AESO's published tariff.[86]

Transmission facility owners (TFOs) recover their revenue requirements from the ISO through tariffs approved by the AUC.[87] The ISO, in turn, recovers all of its costs, including TFO wires costs, line losses, ancillary services, and transmission related administrative costs through its own AUC approved tariff.[88] The ISO's tariff includes a rate for demand

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79 For a useful and authoritative discussion of the regulatory framework for transmission, see *Re AltaLink Management Ltd, Western Alberta Transmission Line Project* (6 December 2012), 2012-327 at para 231, online: AUC <www.auc.ab.ca/applications/decisions/ Decisions/2012/2012-327.pdf>. The regulation of the distribution system and, in particular, the issue of access to the distribution network by a cogenerator is discussed in Part VI, below.

80 *EUA*, *supra* note 59, ss 28–29. Once again, part of the solution here might have involved compulsory divestiture of transmission facilities, but the government decided differently.

81 *Ibid*, s 33. For a more detailed prescription of the ISO's responsibilities, see *Transmission Regulation*, Alta Reg 86/2007, ss 8, 10.

82 *EUA*, *ibid*, s 34, and for the details, see *Transmission Regulation*, *ibid*, ss 11, 38.

83 Both possibilities are contemplated by the *EUA*, *ibid*, s 35. See also *Transmission Regulation*, *ibid*, ss 24–27.

84 *EUA*, *ibid*, s 28.

85 *Ibid*, s 29.

86 *Saskatchewan Power Corp v Alberta (Utilities Commission)*, 2015 ABCA 183, 2015 ABCA 183 (CanLII) at para 38 [*Saskatchewan Power*].

87 *EUA*, *supra* note 59, s 32: the ISO must, *inter alia*, "pay the rates set out in the approved tariff of the owner of each transmission facility." The *EUA* does impose some constraints on tariff design. In particular, s 30(3) provides that:

> The rates set out in the tariff
> (a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and
> (b) are not unjust or unreasonable simply because they comply with clause (a).

88 *Ibid*, ss 119(4). The ISO Tariff is available on the AESO website: Alberta Electric System Operator, *2014 ISO Tariff* (Calgary: AESO, 1 July 2015), online: <www.aeso.ca/downloads/AESO_2014_ISO_Tariff_(2015-07-01).pdf>. For the AUC's most recent decision on the ISO's proposed tariff, see *Re Alberta Electric System Operator, 2014 ISO Tariff Application and 2013 ISO Tariff Update* (21

transmission service (DTS), demand opportunity service (DOS), and supply transmission service (STS).

In approving the ISO tariff, the AUC must take steps to ensure that the just and reasonable costs of the transmission are "wholly charged" to distribution facility owners (DFOs), industrial systems, parties who have made arrangements under section 101 of the *EUA*, and exporters.[89] Any amounts payable by a DFO are recoverable through the DFO's tariff.

In addition, the AUC must ensure that "owners of generating units are charged local interconnection costs to connect their generating units to the transmission system, and are charged a financial contribution toward transmission system upgrades and for location-based cost of losses."[90] The local interconnection costs are detailed in section 28 of the *Transmission Regulation* and section 8 of the 2014 ISO tariff. At the risk of oversimplifying, the costs of connecting generation to the transmission system will be allocated to the generator absent a convincing reason why such costs should be allocated to the system. For example, costs might be allocated to the system where facilities in excess of the minimum required are installed in the interests of overall system planning.[91] In addition, a new generator such as a cogeneration facility seeking interconnection must also be able to make a contribution to the "deep" system costs under the terms of section 28 of the *Transmission Regulation* and section 8 of the 2014 ISO tariff. The system contribution is comprised of two amounts: a standard $10,000/MW charge for any upgrades to existing facilities, and a location-based charge where the generator locates in an area where area generation exceeds load.[92] The location-based charge is intended to reflect the idea that "in regions where generation is greater than area load, the generator needs the transmission system to get its product to market and should pay some contribution based on that use."[93] Both charges are repayable over a ten-year period, provided that the generating unit offers satisfactory performance.[94] This scheme is intended to offer system users some protection from stranded transmission costs.[95]

In addition to the local interconnection charge, location-based loss charges, and the contribution to deep system upgrades, all of which are payable by new generation, including a cogeneration facility, generation is also responsible for line losses.[96] Line loss charges are

August 2014), 2014-242, online: AUC <www.auc.ab.ca/applications/decisions/ Decisions/2014/2014-242.pdf> [*Re ISO Tariff*]. The limited nature of the AUC's review of some elements of the ISO's proposed tariff is discussed at paras 65–72, noting, *inter alia*, that AESO's administrative costs are deemed to be reasonable unless some party can demonstrate that they are not. Similarly, AESO's costs for ancillary services and line losses are deemed prudent or appropriate when incurred and collected in accordance with an approved Rule.

89 *Transmission Regulation*, *supra* note 81, s 47(a)(i); *Re ISO Tariff*, *ibid* at para 400. See further discussion, below.

90 *Transmission Regulation*, *ibid*, s 47(b).

91 *2014 ISO Tariff*, *supra* note 88, Part 8, s 3(3)(c). See also Alberta Energy, Electricity Business Unit, *Transmission Development, The Right Path for Alberta* (Edmonton: Alberta Energy, November 2003) at 11, online: <www.energy.alberta.ca/Electricity/pdfs/transmissionPolicy.pdf> [*Transmission Development Policy*].

92 *Transmission Regulation*, *supra* note 81, s 29(2)–(3).

93 *Transmission Development Policy*, *supra* note 91 at 12.

94 *Transmission Regulation*, *supra* note 81, s 29(4).

95 *Transmission Development Policy*, *supra* note 91 at 6.

96 *Transmission Regulation*, *supra* note 81, s 31. Generation shares responsibility for line losses with export and import paths and potentially other opportunity service customers.

to be recovered based on loss factors that are in turn to be based on the location of generation and the contribution that each makes, if at all, to transmission line losses.[97]

Finally, a person considering investing in new generation will need to assess the risks of congestion on the transmission system, since this may affect the ability to dispatch. Transmission congestion refers to the situation in which there is insufficient capacity on the transmission system to accommodate all-in merit generation over particular lines. This poses both system costs (since out-of-merit generation on the load side of the congestion must be dispatched to make up the shortfall) but also imposes costs on in-merit generation that cannot be dispatched. While both government policy and the *EUA* and *Transmission Regulation* acknowledge that "[a]dequate transmission must be in place to support new generation,"[98] it is inevitable that this will not always work out in practice. There are no transmission rights in Alberta as attested to by numerous AUC decisions.[99] Instead, the *EUA* obliges the AESO to offer timely and non-discriminatory access which has led the AESO to establish a policy which the AUC has described as "connect and compete." "Under this approach, a new entrant will be connected and receive the same priority of service as an incumbent, subject to the potential for a remedial action scheme and the requirement that the AESO alleviate any resulting constraints that may occur under normal operating conditions."[100]

However, it is still necessary for the AESO to adopt rules and remedial action schemes to deal with situations of congestion. The design of these rules is very contentious and the details are beyond the scope of this article.[101] Suffice it for present purposes to note that the risk of congestion and curtailment of dispatch should be factored into investment decisions in any new merchant generation including cogeneration.[102]

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97 *Ibid*, ss 31(1), 35(1)(a), 36(a) ("the owner of a generating unit must pay location-based loss charges or receive credits," s 35(1)(a)).

98 *Transmission Development Policy*, *supra* note 91 at 2; *EUA*, *supra* note 59, ss 17, 33; *Transmission Regulation*, *ibid*, ss 8 et seq.

99 *Re Alberta Electric System Operator, Objections to ISO Rule 9.4 Transmission Constraints Management* (9 April 2009), 2009-042, online: AUC <www.auc.ab.ca/applications/decisions/ Decisions/2009/2009-042.pdf>; *Re Alberta Electric System Operator, Objections to ISO rules Section 203.6 Available Transfer Capacity and Transfer Path Management* (1 February 2013), 2013-025, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2013/2013-025.pdf>; *Re ISO Tariff*, *supra* note 88.

100 *Re ISO Tariff*, *ibid* at para 745; *Saskatchewan Power*, *supra* note 86.

101 See e.g. *Re Complaints by ATCO Power Ltd and ENMAX Energy Corporation regarding ISO Rule Section 302.1: Real Time Transmission Constraint Management* (5 April 2013), 2013-135, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2013/2013-135.pdf>, and the follow-up decision *Re ATCO Power Ltd, ATCO Power letter regarding Commission directions to the AESO in Decision 2013-135* (20 March 2014), 2014-067, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/ 2014/2014-067.pdf>.

102 There are many relevant AESO documents and AUC decisions, but see in particular Alberta Electric System Operator, *AESO Practices for System Access Service* (Calgary: AESO, 31 May 2013), online: <www.aeso.ca/downloads/System_Access_Service_Practice_Final.pdf>. This policy contemplates that remedial action should be applied to the new entrant and not to existing connected market participants, but only on the basis that it is a temporary constraint since the AESO also recognizes that, in granting access, it must make available a plan to remove the constraint. Alternatively, the new entrant may elect to postpone construction so as to align its plans more closely with planned expansions to the transmission system. In effect, this document seeks to provide some certainty and clarity to both new investors and all market participants, and allows at least some opportunity for new investors to bid into the pool pending resolution of constraints.

### D. MARKET SUPERVISION

The province has established a number of new institutions to govern the conduct of those participating in the electricity market, to establish rules for their participation, and to provide for the supervision of the market.[103] The development, implementation, and enforcement of market rules is a shared responsibility of the AESO,[104] the Market Surveillance Administrator (MSA),[105] and the AUC.[106]

## VI. REGULATORY TREATMENT OF COGENERATION FACILITIES IN ALBERTA

There is no specific legislation concerning cogeneration in Alberta. Instead, the existing legislation deals more broadly with the concept of self-generation, (users who generate their own electricity to meet all or part of their demand). The principal relevant legislation is the *HEEA*[107] and the *EUA*.[108] The AUC's Rule 007 prescribes the background and technical information that an applicant must include when applying for an approval from the AUC.[109] The AUC has described the interaction between these two statutory regimes in a number of decisions as follows:[110]

> The purpose of the *Electric Utilities Act* is set out in Section 5 and generally focuses upon the efficient development and operation of the electricity market. In comparison, the *Hydro and Electric Energy Act* establishes the regulatory framework for the construction and operation of electric-related infrastructure and facilities in Alberta. The *Electric Utilities Act* and the *Hydro and Electric Energy Act* may be considered partner legislation through which the former establishes the regulatory framework for utility matters, such as a utility's right to provide service to customers in its service area, while the latter regulates the construction and operation of electrical infrastructure. Given this inter-relationship, the overlapping considerations in the *Hydro and Electric Energy Act* and the *Electric Utilities Act*, and the mutual reference in the two pieces of legislation, specific provisions of the *Hydro and Electric Energy Act* must be read with regard to the *Electric Utilities Act*.

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103 This was necessary because markets for a commodity like electricity do not just emerge, especially where the incumbents continue as dominant players with significant market power.

104 For the ISO's rule-making functions, see *EUA*, *supra* note 59, s 20(1).

105 The MSA is governed by Part 5 of the *Alberta Utilities Commission Act*, SA 2007, c A-37.2 [*AUCA*]. The MSA monitors Alberta's electricity and retail natural gas markets to ensure that they operate in a fair, efficient, and openly competitive manner. The MSA also has other responsibilities under the *AUCA*. The Court of Queen's Bench has described the MSA as "the 'watch dog' over the electricity market in Alberta": *Market Surveillance Administrator v Enmax Energy Corp*, 2007 ABQB 309, 420 AR 237 at para 1, Macleod J. There is now a considerable body of jurisprudence on the MSA, much of it relating to its powers of investigation and, in particular, its authority over the seizure and production of records and documents: see *TransAlta Corp v Market Surveillance Administrator*, 2014 ABCA 196, 577 AR 32; *TransAlta Corp v Market Surveillance Administrator*, 2015 ABQB 180, 2015 ABQB 180 (CanLII).

106 The AUC holds a supervisory role over both the ISO and the MSA, as well as rate setting responsibilities for the ISO, TFOs, and DFOs.

107 *Supra* note 13.

108 *Supra* note 59.

109 *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*, AUC Rule 007 (11 March 2015), online: AUC <auc.ab.ca/acts-regulations-and-auc-rules/rules/Documents/Rule007.pdf> [*Rule 007*].

110 See e.g. *Re Blaze Energy Ltd. Application for an Exemption under Section 24 of the Hydro and Electric Energy Act* (17 April 2014), 2014-108 at para 13, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2014/2014-108.pdf> [footnotes omitted]; *Re Grande Cache Coal Corporation, Application for an Exemption Under Section 24 and a Connection Under Section 18 of the Hydro and Electric Energy Act* (15 March 2010), 2010-115 at para 63, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2010/2010-115.pdf> [*Re Grande Cache*] [footnotes omitted].

This part of the article focuses on (1) the approval for the construction and operation of a power plant; (2) connection orders; (3) on-site distribution; (4) transmission for own use; and (5) Industrial System Designations.

### A. APPROVAL FOR THE CONSTRUCTION AND OPERATION OF A POWER PLANT

Sections 3 and 11 of the *HEEA* deal with the construction and operation of a power plant, including a cogeneration facility. Section 11 provides that no person may construct or operate a power plant without the approval of the AUC, while section 13 creates an exception to this requirement where a person is "generating or proposing to generate electric energy solely for the person's own use, unless the Commission otherwise directs."[111] AUC Rule 007 section 3 is effectively an "otherwise directs" provision, since it requires an applicant for a plant of 10 MW or greater to "demonstrate that the applicant plans to generate electricity solely for the applicant's own use" and on the basis of such information and other information "[t]he Commission will determine whether an approval must be issued or whether the plant is exempt."[112]

In considering an application under section 11, the AUC must have regard to the purposes of both the *HEEA* and the *EUA*, but section 3 of *HEEA* provides that the AUC must *not* "have regard to whether the [proposed] generating unit is an economic source of electric energy in Alberta or to whether there is a need for the electric energy to be produced by such facility in meeting the requirements for electric energy in Alberta or outside Alberta."[113] While this section precludes consideration of market demand, section 17 of the *AUCA* requires the Commission to assess whether the power plant "is in the public interest" having regard to the social, economic, and environmental effects of the plant.[114] As a matter of practice, AUC decisions typically contain a summative statement to the effect that the proposed power plant is in the public interest.

### B. CONNECTION ORDERS

Most cogeneration facilities will need to be connected to the power grid either to purchase additional supply or to sell any excess into the power pool, or both.[115] Any connection to the Alberta Interconnected Electric System (AIES) requires an application to the AUC under section 18 of the *HEEA*.[116] In support of its application, a party must file particulars of the proposed connection, as well as any relevant operating agreement with other parties, and

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111 *Supra* note 13, ss 11, 13; *Rule 007*, *supra* note 109 at 9–21.

112 *Rule 007*, *ibid* at 10. See e.g. *Re Paramount Resources Ltd, Musreau Natural Gas Power Plant* (17 June 2015), 3608-D01-2015, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/ 2015/3608-D01-2015.pdf>; *Re Paramount Resources Ltd Power Plant Exemption Musreau Gas Plant Facility* (18 July 2013), 2013-268, online: AUC <www.auc.ab.ca/applications/decisions/ Decisions/2013/2013-268.pdf>. In addition to the documentation and technical information of Rule 007 an applicant must also address Rule 012 concerning the requirements for noise control: *Noise Control*, AUC Rule 012 (1 April 2013), online: AUC <www.auc.ab.ca/acts-regulations-and-auc-rules/rules-Documents/Rule012.pdf>.

113 *Supra* note 13, s 3. This is consistent with the idea that the decision to construct new generation should be a market-based decision rather than the decision of a regulator.

114 *Supra* note 105, s 17.

115 See discussion in Part V.A, above.

116 *Supra* note 13, s 18; *Rule 007*, *supra* note 109 at 19.

information required by section 5 of Rule 007.[117] Where the proposed connection is at a voltage of less than 69 kilovolts (kV) the Rule provides that application must be accompanied by a statement of support from the local distribution company. Where the proposed connection is at a voltage of 69 kV or greater, the application must include information from the ISO assessing the implications of the proposed addition for the AIES. The application should also discuss the extent of any capital contribution from the proponent to the costs of the interconnection (see Part V.C, above). In making an order under section 18, the AUC may prescribe any terms and conditions it considers suitable as well as the payment of compensation if agreement cannot be reached between the relevant parties.[118]

Section 18 applies both to a generator seeking connection to a transmission line or distribution system and to the owner of transmission or distribution facilities seeking access to the facilities of the generator or the owner of a related industrial system.[119]

### C. ON-SITE ELECTRICITY DISTRIBUTION

The owner or operator of a cogeneration facility may wish to distribute electric energy within its own site. Absent an Industrial System Designation,[120] this activity will engage both sections 24 and 25 of the *HEEA* and trigger the need to secure the AUC's approval unless exempted.

The *HEEA* defines the term "electric distribution system" (EDS) as "any system, works, plant, equipment or service for the delivery, distribution or furnishing of electric energy directly to the consumers, but does not include a power plant or transmission line."[121] The distribution function in Alberta is ordinarily an exclusive franchise of the entity holding a designated service area (DSA) designation for that particular area of the province.[122]

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117 *Rule 007*, *ibid* at 18–20.

118 *HEEA*, *supra* note 13, s 18.

119 This has been the subject of limited comment by the AUC and its predecessor in several decisions. See in particular, *Re ESBI Alberta Ltd, Syncrude Canada Limited/Albian Sands Energy Project* (30 August 2001), 2001-71, online: EUB <www.auc.ab.ca/applications/decisions/decisions/2001/ 2001-71.pdf> (access to Syncrude transmission facilities included in an ISD granted on an interim basis; much of the discussion deals with the treatment of liability issues rather than the question of whether or not access should be granted); *Re Imperial Oil Resources Limited Industrial System Designation Cold Lake Expansion Project* (4 March 1999), D 99-4, online: EUB <www.aer.ca/documents/decisions/1999/d99-04.pdf> [*Re Cold Lake*] (discussion as to whether the AUC should condition Imperial's ISD with terms and conditions relating to future access by the ISO or TFOs to transmission facilities included within the ISD area and owned by Imperial. The AUC rejected these arguments, holding that the matter was already well dealt with in s 40 of the *EUA* and s 17 of the *HEEA*).

120 The Industrial System Designation is discussed below in Part VI.E. In *Re Shell Peace River In-situ Expansion Carmon Creek Project Industrial System Designation, Power Plant, 240-kV Substation and 34.5-kV Distribution System* (15 April 2014), 2014-068 at paras 8, 50, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2014/2014-068_Errata.pdf> [*Re Shell Peace River*]. Shell Canada Ltd asked the AUC for approval to construct a 34.5 kV distribution system. The Commission concluded that it did not need to deal with this as a separate matter, observing that Shell was free to go ahead with its plans "pursuant to the industrial system designation granted by the Commission in this decision" (*ibid* at para 50). In some cases, however, there may be a difficult timing issue for a developer who may want to provide its own diesel generation until its cogeneration facility comes on stream and it can acquire an ISD.

121 *Supra* note 13, s 1(1)(b).

122 *Ibid*, ss 25–29, 42. The recognition of designated service areas is largely based on historical practice with the critical date being 1 June 1971, the date when the first *HEEA* entered into force. The utility providing service in an area was deemed to be the designated service provider. Since then, the relevant regulator has followed a more systematic practice of issuing the appropriate designations. Anomalies are identified from time to time as shown, for example, by a recent decision involving an electric distribution system operated by the University of Alberta: *Re University of Alberta, Electric Distribution*

Under section 25 of the *HEEA*, no person shall construct or operate an EDS, or alter the service area of an existing EDS, without the approval of the AUC. Such approval shall not be issued unless the Commission is satisfied (having regard to other sources of energy and other relevant circumstances) that it is in the public interest in light of "the present and future need for the extension of electric service throughout Alberta."[123] Alternatively, the Commission may approve the construction or operation of an EDS within the service area of another EDS where this will result in a consumer receiving service who is not being provided with service by the incumbent.[124]

Section 24 of the *HEEA* exempts a person proposing to distribute electric energy solely on its own lands (including leased lands) from the EDS provisions of the *Act*, "unless the Commission otherwise directs" so long as the distribution of electricity does not cross a public highway, or if it crosses a public highway and the voltage level of the distribution is 750 volts or less.[125] In practice, and notwithstanding, the "otherwise directs" language, parties actively seek exemption orders from the Commission.[126] In such a case, if the formal conditions (with respect to ownership and public highways) can be met, the AUC must still satisfy itself that the exemption is in the public interest.[127]

The leading decision on section 24 is the EUB's MEG Energy decision of 2006.[128] In that case, MEG brought its section 24 application in advance of its Industrial System Designation[129] application for its Christina Lake pilot facility because it wished to construct the distribution feeders for its pilot plant, production pad and source wells, and pumping stations all within its lease boundaries before its own source of generation became available. Fortis Alberta, which held the DSA, opposed the application principally on the grounds that it would be contrary to the public interest to permit a section 24 exemption if the incumbent regulated utility is ready and able to provide timely service.[130] In its decision, the EUB evidently interpreted the "otherwise directs" language of section 24 as imposing on Fortis the onus of establishing why it would not be in the public interest to grant the order. The EUB ultimately concluded that Fortis had failed to meet that test.[131] While there is language in the decision which cautions that the EUB's approval is specific to this application, that similar outcomes should not be automatically expected in "any future applications by MEG or any other operator," and that the exemption order might be in jeopardy should a public highway bisect the land or should MEG cease to own or lease all the relevant lands, the decision does seem robust, appropriate, and consistent with the purposes of the *HEEA* and

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*System* (21 December 2012), 2012-355, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2012/2012-355.pdf>.

123 *HEEA*, *supra* note 13, s 25(2).

124 *Ibid*, s 26.

125 *Ibid*, s 24(1)(a). See also *Re Electrification Association*, *supra* note 61. This decision established that there is some overlap between the service areas of REAs (defined "as being the members [of the REA] served within the geographic service area") and the service areas of public electric utilities (*ibid* at para 62).

126 See e.g. *Re Grande Cache*, *supra* note 110; *Re MEG Energy Corporation, Construct and Operate a 25-kV Electrical Distribution System* (15 June 2006), 2006-057, online: EUB <www.auc.ab.ca/applications/decisions/Decisions/2006/2006-057.pdf> [*Re MEG*].

127 *Re Grande Cache*, *ibid* at para 66; *Re MEG*, *ibid* at 4.

128 *Re MEG*, *ibid*.

129 See Part VI.E for more details on industrial system designations.

130 *Re MEG*, *supra* note 126 at 13.

131 *Ibid* at 14.

the *EUA* as interrelated statutes.[132] Furthermore, the decision stands for the proposition that the applicant need only show that its application meets the formal conditions of section 24; it does not need to show that the proposed order is in the public interest. Rather, it suggests that if the applicant can meet the formal conditions, the onus is on the incumbent utility to show why an exemption order is not in the public interest.

Section 101 of the *EUA* is also relevant where a party seeks direct access to *transmission* facilities within the service area of an EDS. While that section requires any person wanting to obtain distribution service to deal with "the owner of the electric distribution system in whose service area the property is located,"[133] it also provides that a person with an interval meter may enter into an arrangement with the ISO to receive system access service[134] directly from the transmission system provided that such a person has the prior approval of the EDS owner and the ISO. Thus, as the AUC confirmed in its decision on the AESO's 2010 tariff application, the *EUA* requires the approval of both the EDS owner and the ISO where a customer wishes to take service directly from the ISO.[135]

### D. TRANSMISSION OF ELECTRICITY FOR OWN USE

As a general rule, no person may construct or operate a transmission line without a permit and licence from the AUC.[136] However, section 16 of the *HEEA* provides that a person proposing to transmit electric energy over its own lands and solely for its own use does not require a permit or licence, unless the AUC otherwise directs, provided that the proposed line does not cross a public highway.[137] There is a similar exemption for owners of industrial systems, which is slightly broader since the "use" qualification extends to use "solely by that industrial system" and is not confined to use by the owner, and the prohibition on crossing a highway does not apply.[138]

The AESO believes that, in principle, any market participant should have the option to construct, own, and operate the non-bulk transmission facilities required to connect that market participant's facilities to the AIES. The AESO recognizes that market participants may wish to do this for a number of reasons, including the perceived high costs of having the incumbent TFO undertake the work and the extended schedules associated with the TFO-led projects.[139] The AESO considers that the *EUA* supports this policy, and in particular section 35 allows the AESO to request a market partcipant to provide it with a proposal for building transmission. A market participant who builds a transmission project becomes a TFO with

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132 *Ibid* at 15.
133 *Supra* note 59, s 101(1); *Re Grande Cache*, *supra* note 110 at para 83.
134 *EUA*, *ibid*, s 1(1)(yy) defines "system access service" as "the service obtained by market participants through a connection to the transmission system, and includes access to exchange electric energy and ancillary services."
135 *Re Alberta Electric System Operator, 2010 ISO Tariff* (22 December 2010), 2010-606 at para 421, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2010/2010-606.pdf>.
136 *HEEA*, *supra* note 13, ss 14–15.
137 *Ibid*, s 16(1)(a).
138 *Ibid*, s 16(1)(b).
139 Alberta Electric System Operator, *Market Participant Choice to Construct, Own, Operate and Maintain Transmission Lines Connecting its Faciities to the Interconnected Electric System* (Calgary: AESO, 29 September 2011) at 3, online: <www.aeso.ca/downloads/Discussion_Paper_-_MP_Choice_vFinal_Sept_28.pdf>.

all the responsibilities of a TFO under the *EUA*, including the duty to submit a tariff to the AUC for approval (unless exempted by the AUC).[140]

## E. INDUSTRIAL SYSTEM DESIGNATION

To encourage large industrial project operators to self-generate, the government introduced the concept of an "industrial system designation" (ISD) under the *HEEA* in 1998.[141] Alberta Energy's "Industial Systems Policy Statement"[142] clarifies the implications of this designation while the AUC's Rule 007 prescribes the technical information that an applicant must include when applying for such a designation. The *HEEA* defines an industrial system as "the whole or any part of an electric system primarily intended to serve one or more industrial operations of which the system forms a part and designated by the Commission as an industrial system."[143] An ISD may include several major components of an electric system, such as power plants (and hence cogeneration units), substations, and transmission lines. A party may seek an ISD in conjunction with its other applications under the *HEEA* or make an application for facilities, which have already been approved.[144]

Section 4 of *HEEA* establishes four principles as well as a list of criteria that the AUC must consider in making a designation.[145] The remainder of Part VI.E discusses the principles and criteria and refers to key AUC decisions interpreting and applying the criteria (principally in the footnotes) as well as the government's Industrial Systems Policy Statement.[146] This Part concludes with a summary of the implications and advantages associated with an ISD order. In general, such an order serves to provide the ISD operator

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140 It is not entirely clear that the AUC and the AESO are *ad idem* on all of these points; see the discussion below of *Re Imperial Oil Resources Ventures Ltd, Reasons for Industrial System Designation* (10 February 2009), 2009-020A, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2009/2009-020A.pdf> [*Re Industrial System*].

141 Alberta, Legislative Assembly, *Hansard*, 24th Leg, 2nd Sess (31 March 1998) at 1266, online: Legislative Assembly of Alberta <www.assembly.ab.ca/ISYS/LADDAR_files/docs/hansards/han/legislature_24/session_2/19980331_2000_01_han.pdf>.

142 Alberta Energy, "Industrial Systems Policy Statement" (Edmonton: Alberta Energy, June 1997), online: <www.energy.alberta.ca/Electricity/pdfs/IndustrialSystemsPol97.pdf>.

143 *HEEA*, *supra* note 13, s 1(1)(g). It is perhaps important to emphasize the "primarily intended to serve" language of the definition. In *Re Cold Lake*, *supra* note 119 at 6, the EUB approved the inclusion of service to pumps for pipelines owned by a third party that delivered diluent to Imperial's operation. The Board observed that the pipelines exclusively served Imperial's operations and held that they should be treated as part of Imperial's system.

144 For an example of the latter, see *Re Industrial System*, *supra* note 140.

145 *Supra* note 13. Overall, these principles reflect the purposes of the *HEEA*, s 2(a), "to provide for the economic, orderly and efficient development and operation, in the public interest, of hydro energy and the generation and *transmission of electric energy* in Alberta" [emphasis added].

146 It is appropriate to express some caution in referring to this policy statement. In *Re Industrial System*, *supra* note 140, and many other decisions, the AUC declined to rely on the Department's *Transmission Development Policy*, *supra* note 91 in reaching its decision (*Re Industrial System*, *ibid* at paras 24–25):

> The Commission finds that by enacting the ISD provisions the legislature has carved out the ISD from the general legislative scheme of the *HEEA* and the *EUA* and established specific rules for ISDs. For this reason, the *Transmission Regulation* would not be applicable as it generally sets out the duties of the Independent System Operator and TFOs.
>
> Regarding the arguments based on the *Transmission Development Policy*, the Commission is of the view that it need not consider the above-mentioned portions of the Transmission Development Policy as the legislation under which ISDs are established clearly sets out the intent of the legislature. The Commission is of the opinion that government policies are only useful for purposes of interpretation to the extent that the provisions in the *HEEA* or *EUA* are unclear.

The same rationale must apply to any consideration of the "Industrial Systems Policy Statement" (*supra* note 142).

with an exemption from some of the provisions of the *HEEA* and the *EUA* that would otherwise apply.

### 1. THE ISD PRINCIPLES

The principles are as follows. First, the ISD must be consistent with the objective of giving appropriate economic signals such that industrial processes will develop their own internal electricity supply where that is the most economical source of generation.[147] This principle requires the applicant to demonstrate that the internal electricity supply, such as on-site generation, is the most economic source of power for the industrial complex.[148] For example, "if the industrial complex uses cogeneration to produce electric and thermal energy, the applicant should provide a comparison of the costs of the internal supply of electricity and process heat" versus the alternative of contracting electrical supply from the AIES and installing *in situ* heat exchangers or boilers to satisfy the thermal requirements of the industrial process.[149]

Second, an ISD must support "the efficient exchange, with the interconnected electric system, of electric energy that is in excess of the industrial system's own requirements," as well as improved voltage stability and reduction of losses and congestion of transmission lines.[150] In order to meet this principle, Rule 007 requires an applicant to provide an assessment of losses and congestion on transmission lines due to the electric power that the industrial complex would supply to the AIES, taking into account other existing generation and generation under construction.[151] The efficient exchange principle does not necessarily require that the proposed facility will be interconnected with the AIES. In a 2011 application in relation to a cogeneration project for the McKay SAGD project, the applicant had no plan to interconnect because interconnection would require the construction of a 16 or 22 kilometre (km) transmission line which would not be economical. The AUC granted the applicant relief from the strict application of the principle, but directed it to apply for an interconnection order within a reasonable time of transmission facilities being built in the vicinity of the project.[152]

The third principle requires that an ISD should not facilitate "the development of independent electric systems that attempt to avoid costs associated with the interconnected

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147 *HEEA*, *supra* note 13, s 4(2)(a); "Industrial Systems Policy Statement," *ibid* at 1.
148 *Rule 007*, *supra* note 109 at 31.
149 *Ibid*. See e.g. *Re Imperial Oil Resources Limited, Nabiye Project - Cogeneration Plant, Transmission Facilities, and Industrial System Designation* (2 September 2010), 2010-431 at para 38, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2010/2010-431.pdf> [*Re Nabiye Project*] (Imperial provided a 30-year cash flow comparison of a "purchased power scenario" and a cogeneration scenario); *Re Shell Peace River*, *supra* note 120 at para 22 (Shell performed a high-level economic comparison of the cost of providing electricity and steam based on three scenarios: (1) steam only case – capital cost of stand-alone boilers and utilization of produced treated gas and purchased natural gas; (2) base case – cost of steam only case for steam production and cost of electricity to be purchased from the AIES; (3) cogeneration case – cost of capital, operating, and tariff for steam and electricity for cogeneration, including revenue offsets from electricity to be sold to the AIES).
150 *HEEA*, *supra* note 13, s 4(2)(b).
151 *Supra* note 109 at 31.
152 *Re Southern Pacific Resource Corp, Industrial System Designation for Electrical System of McKay SAGD Project* (30 June 2011), 2011-291 at paras 17–23, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2011/2011-291.pdf> [*Re Southern Pacific*].

electric system" and uneconomical bypass of the interconnected electric system.[153] The AUC may take into account whether there are any other electric facilities, including transmission lines, reasonably available to the proponent.[154] In its *Re Industrial System* decision, the AUC rejected the contention that the construction of new transmission facilities should always be assigned to incumbent TFOs and dismissed concerns as to a patchwork quilt of ownership of transmission.[155] Evidence that the ISD owner is maintaining ISO contracts for both supply transmission services (STS) and demand transmission service (DTS) supports the conclusion that the ISD owner is not seeking to avoid the costs associated with the interconnected system.[156]

Finally, "duplication of the interconnected electric system must be avoided where it is more economical" to use utility-owned transmission or distribution facilities existing in the service area where the industrial system will be located.[157]

### 2. THE ISD CRITERIA

The AUC must have "regard to" the above principles in considering an ISD application but it may only designate an electric system as "industrial" if it is satisfied that seven criteria have been met (although as we shall see, section 4(5) affords the AUC a degree of flexibility in cases where the criteria are "substantially met").[158] The first criterion is concerned with generating units and with integration. The electric system must include at least one generating unit that has substantial capacity in comparison with the on-site load and is located on the property of the one or more of the industrial operations it is intended to serve.[159] In addition, there must be a high degree of integration of the electric system with one or more industrial operations the electric system forms part of and serves, and a high degree of integration of the components of the industrial operations.[160] The clearest case would involve integrated industrial processes using shared equipment and continuous product flow.[161] Facilities may be interconnected by substantial items of common site infrastructure

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153 *HEEA*, *supra* note 13, s 4(2)(c); "Industrial Systems Policy Statement," *supra* note 142 at 1.

154 See e.g. *Re Southern Pacific*, *supra* note 152; *Re Shell Peace River*, *supra* note 120 at paras 25–31.

155 *Supra* note 140 at paras 11–14, 19–25, 37. In some cases, the ISD owner may contract with a TFO for the construction and operation of facilities, such facilities not forming part of the rate base of the regulated TFO, see *Re Cenovus FCCL Ltd, Foster Creek ISD Amendment, ATCO Electric Ltd, Kodiak 12105 Substation Interconnection* (29 September 2014), 2014-278 at para 16, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2014/2014-278.pdf> [*Re Cenovus*]. To some extent this runs contrary to the government's 2003 *Transmission Development Policy*, *supra* note 91 at 4, which spoke against the dangers of a patchwork quilt of transmission ownership which would not have "the same level of coordination or economy of scale and … would not operate as reliably and efficiently." But as noted, the AUC will only resort to a policy statement where it finds an ambiguity in the legislation (see *supra* note 146).

156 *Re MEG Energy Corp, Amend Christina Lake Industrial System Designatoin* (15 December 2011), 2011-496 at para 21, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2011/2011-496.pdf>; *Re Pengrowth Energy Corporation, Lindberg SAGD Industrial System Designation* (20 August 2013), 2013-308, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2013/2013-308.pdf>.

157 *HEEA*, *supra* note 13, s 4(2)(d); "Industrial Systems Policy Statement," *supra* note 142 at 1; *Rule 007*, *supra* note 109 at 31.

158 *HEEA*, *ibid*, ss 4(2)–(3), (5).

159 *Ibid*, s 4(3)(a); *Rule 007*, *supra* note 109 at 30. Absent a generating facility, there can be no ISD Order: see *Re Grande Cache*, *supra* note 110 at para 89.

160 *HEEA*, *ibid*, s 4(3)(a); *Rule 007*, *ibid* at 30.

161 "Industrial Systems Policy Statement," *supra* note 142 at 2. In *Re Industrial System*, *supra* note 140 at para 40, the AUC approved the inclusion of a 72-kV transmission line from the main site to a river water intake approximately 18 miles from the main lease area. This was justified on the basis that "a source of water is essential for the recovery of bitumen and that, in order to supply this water, electricity is required at the [river water intake] facility."

directly required by the industrial operation such as process piping, raw material and finished product lines, or conveyors.[162] Where the industrial operations draw on a geographically contiguous resource (oil, gas, or mineral pool), there is a strong indication of an integrated process if ownership of the resource is the same, and there is substantial common site infrastructure.[163] Linkages based only on electric or thermal energy supply may be insufficient.[164]

The second criterion is concerned with production. The integrated operations must process a feedstock, produce a primary product, or manufacture a product.[165] In the case of oil sands operations, the product will typically be described as bitumen or diluted bitumen.

The third criterion is concerned with ownership. All of the components of the industrial operations should have a common owner.[166] Common ownership requires a single person, including a joint venture or partnership, to own the components of the industrial operations.[167] Multiple owners are not necessarily excluded, because section 4(4) affords the AUC the discretion to make an ISD if, despite the lack of common ownership, it is satisfied that "all of the separately owned components and all of the industrial operations are components of an integrated industrial process."[168] In practice, the AUC routinely approves ISD orders relying on this discretionary authority.[169] The existence of multiple owners may suggest that that the operations are distinct and non-integrated, and that a supplier-customer relationship exists rather than an integrated industrial process.[170] Thus, in such a case, there is a greater burden on the applicant to demonstrate that the assets are, in fact, all components of an integrated industrial process.[171] The Industrial Systems Policy Statement suggests that operations with multiple owners may be considered an integrated process if the outputs and management of the operations are coordinated in a way that contributes to the production of the final output of the process.[172] In addition, the Policy recognizes that generating facilities

162 "Industrial Systems Policy Statement," *ibid* at 2.

163 *Ibid*; *NADC Report*, *supra* note 24 at 37. In *Re Cold Lake*, *supra* note 119 at 6, Imperial sought an ISD for a 220MW cogeneration plant that would provide service to four separate processing plants and a pump station and water well. The EUB rejected arguments from intervenors that Imperial's operation was not sufficiently integrated. The Board observed that there was a commingled product from a continuous leased area.

164 "Industrial Systems Policy Statement," *ibid* at 2.

165 *HEEA*, *supra* note 13, s 4(3)(b).

166 *Ibid*, s 4(3)(c).

167 "Industrial Systems Policy Statement," *supra* note 142 at 3.

168 *HEEA*, *supra* note 13.

169 See e.g. *Re Cenovus*, *supra* note 155 at paras 16, 21: ATCO would own and operate the transmission facilities within the ISD previously owned by Cenovus, the holder of the ISD; *Re Cenovus FCCL Ltd, Construct and Operate a 95-MW Cogeneration Power Plant, Construct and Operate Sunday Creek 5395 Substation, Industrial System Designation and Interconnection of the Christina Lake Industrial System Designation* (23 July 2012), 2012-196 at para 55, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2012/2012-196.pdf>: Cenovus Christina Lake ISD distribution facilities were owned by Fortis and charged on the basis of a special AUC approved tariff (see *Re FortisAlberta Inc, Application for Special Facilities Charge* (2 May 2011), 2011-176, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2011/2011-176.pdf>).

170 "Industrial Systems Policy Statement," *supra* note 142 at 3.

171 *Ibid*.

172 *Ibid*; for instance, in *Re Cold Lake*, *supra* note 119 at 6, the EUB granted an ISD to Imperial even though the pipelines used to deliver diluent to its facilities and transport products away from the site were owned by AEC. The EUB reached this conclusion after noting that the function of the AEC pipeline on the site was *exclusively* to serve Imperial's operation.

that produce electric energy for use by an industrial system may be owned by a person other than the owner of the various operations of the integrated process.[173]

The fourth criterion is concerned with the output. The AUC must be satisfied that the output of each component within the industrial operation is required by that operation and is necessary to constitute its final products.[174] This criterion too may be waived if the AUC is satisfied that "all of the separately owned components and all of the industrial operations are components of an integrated industrial process."[175] The government's "Industrial Systems Policy Statement" suggests that operations that have a supplier-customer relationship, or where a substantial portion of the output of any operation is sold outside this arrangement, this may indicate that an integrated process does not exist.[176] Similarly, an output from an operation that is sold to the markets but that is not the final product of the integrated process indicates that the operations are not part of an integrated process.[177]

The fifth criterion is concerned with management. There must be a high degree of integration of the management of the components and processes of the industrial operations.[178] The "Industrial Systems Policy Statement" suggests that the clearest demonstration of this would be where the industrial operations were under single management, and changes in levels of output for one operation are directly reflected in comparable changes in other operations.[179] If operations are separately managed, such that they operate at different levels for sustained periods, the basis for claiming integration is weak.[180]

The sixth criterion is concerned with investment. The applicant must demonstrate a significant investment in both the expansion and extension of the industrial operations processes and development of the electricity supply.[181]

The last criterion is concerned with proximity. In general, it is easier for the AUC to identify the electric system as industrial if there is proximity between the industrial operations and facilities.[182] Where the site infrastructure extends beyond a single contiguous property, the applicant bears a more onerous burden of demonstrating that the system is an integrated industrial process.[183] In such a case, the applicant must demonstrate that it can provide its own distribution or transmission facilities to interconnect the integral parts of the industrial operation at an overall cost equal to, or lower than, the tariffs applicable for distribution or transmission in the service area where the industrial operation is located.[184]

173 "Industrial Systems Policy Statement," *ibid* at 3; this understanding is also reflected in the *EUA*, *supra* note 59, ss 2(1)(b), 2(3) (exemption for self-generation).
174 *HEEA*, *supra* note 13, s 4(3)(d).
175 *Ibid*, s 4(4).
176 *Supra* note 142 at 3.
177 *Ibid*.
178 *HEEA*, *supra* note 13, s 4(3)(e).
179 *Supra* note 142 at 3.
180 *Ibid*.
181 *HEEA*, *supra* note 13, s 4(3)(f). For instance, in *Re Shell Peace River*, *supra* note 120 at para 41, the AUC was satisfied that this criterion was met because Shell submitted that the total capital investment would be several billion dollars of which approximately $1 billion would relate to the development of cogeneration facilities.
182 "Industrial Systems Policy Statement," *supra* note 142 at 3.
183 *Ibid* at 4.
184 *HEEA*, *supra* note 13, s 4(3)(g).

In *Re Industrial System*, the AUC ruled that the term "tariff" as used in this section of the *HEEA* must be taken to include both rates and terms and conditions, including any customer contributions that Imperial would be required to make if the TFO were to construct these facilities. Thus, it was appropriate to make a global comparison of all costs and not just resulting rates.[185]

Even if the application has not met all of the criteria provided, section 4(5) of the *HEEA* gives the AUC the residual discretion to make an ISD order if it is satisfied that all of the criteria have been "substantially met" and that there will be "a significant and sustained increase in efficiency in a process of the industrial operation or in the production and consumption of electric energy by the industrial operation as a result of the integration of the electric system with the industrial operations the electric system forms part of and serves."[186]

In its decisions on ISD Order applications, the Commission typically finds the ISD to be in the public interest in accordance with section 17 of the *AUCA*.[187] There would appear to be no requirement or basis for such a determination since, while section 17 requires the AUC to make such determinations with respect to power plants and transmission lines, it says nothing about ISDs.

### 3. THE IMPLICATIONS OF AN INDUSTRIAL SYSTEM DESIGNATION

The implications of an ISD are far from transparent. In *Re Industrial System*, the AUC emphasized two points. First, "an ISD is an electric system that is generally exempted from the *HEEA* and the *EUA* provisions which govern the electric industry in Alberta because it is designed to serve only the industrial system to which it relates."[188] Second, "by enacting the ISD provisions the legislature has carved out the ISD from the general legislative scheme of the *HEEA* and the *EUA* and established specific rules for ISDs."[189] The AUC has also stated that the purpose of an ISD is "to allow a designated industrial site to develop its own internal electric system" and that this means "not only internal generation but also internal transmission and distribution of electric energy."[190] Accordingly, unless stipulated otherwise, the holder of an ISD approval can "construct and operate its own internal electric transmission and distribution without further approval."[191]

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185 *Supra* note 140 at para 66. The AUC concluded that Imperial had discharged its burden in that case.

186 *Supra* note 13. To determine whether this condition is met, the applicant is generally required to provide a thermal energy balance. Note that the "substantially met" requirement only applies to the criteria and not the principles, although in *Re Southern Pacific*, *supra* note 152 at para 43 the Commission seemingly applied the test to both.

187 *Supra* note 105.

188 *Supra* note 140 at para 19.

189 *Ibid* at para 24.

190 *Re EnCana FCCL Ltd, Amendment to Industrial System Designation Order U2009-313 Foster Creek Thermal Oil Sands* (26 January 2010), 2010-037 at paras 11–12, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2010/2010-037.pdf> [*Re EnCana*].

191 *Ibid* at para 15. In an early decision, *Re Cold Lake*, *supra* note 119 at 9, the EUB was much more equivocal in response to concerns that Imperial might simply bypass existing transmission facilities. In that decision, the EUB acknowledged that Imperial would undoubtedly need some transmission and distribution facilities and that any construction of transmission facilities by Imperial "should be orderly and avoid undue redundancy." Accordingly the EUB ordered Imperial to negotiate available options, failing which Imperial might apply to the Board for appropriate orders. This of course was far less than the exemption that Imperial sought and was effectively a contrary direction from the presumed exemption offered by the statute.

An ISD forms the basis for exempting "energy produced from and consumed by an industrial system" from the application of all or any terms of the *EUA* through sections 2 and 117 of that *Act*. Section 2(1) provides that the *EUA* does not apply to four categories of energy of which two are relevant here: (b) electric energy produced and consumed solely on a person's property;[192] and (d) electric energy exempted by the AUC "in accordance with rules made under section 117."[193]

Section 117 provides that the AUC may make rules exempting a facility or class of facilities from the definition of "electric utility" and may also make rules exempting the electric energy "produced from and consumed by an industrial system."[194] The AUC may impose terms and conditions on such an exemption including a condition that the owner of an industrial system should be "responsible for paying a just and reasonable share of the costs associated with the interconnected electric system."[195] The AUC has never made generic rules for ISDs under section 117, but it routinely makes individual exemption rulings in response to specific ISD applications to the effect that "electric energy produced from, and consumed by, the industrial system [is exempt] from the operation of the *Electric Utilities Act*."[196]

An ISD has several implications. First, the electric energy produced by the ISD does not have to be exchanged through the Power Pool if it is not transmitted through the facilities of the interconnected electric system.[197]

Second, the owner of an ISD does not have to purchase electric energy from the owner of the EDS in whose area the industrial system is located.[198]

Third, the owner of a transmission facility included in an ISD has duties that vary substantially from those of a TFO under the *HEEA* and the *EUA*.[199] The *Transmission Regulation* is not applicable to ISDs as it generally sets out the duties of the ISO and TFOs.[200] For example, there is no duty on an owner of an ISD to file a tariff, to submit a needs identification document, to submit a facility approval at the direction of the Independent System Operator, or to consider system growth when constructing transmission facilities to be included in an ISD.[201] However, section 18 of the *HEEA* and section 40 of the

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192 The generating unit does not have to be owned by the owner or tenant of the property: *EUA*, *supra* note 59, s 2(3).
193 *Ibid*.
194 The *EUA*, *ibid*, does not further elaborate on the AUC's rule-making power. *AUCA*, *supra* note 105, s 76, addresses the Commission's power to make rules and specifies that the Commission need not hold a public hearing before making a rule. The section does not otherwise cross-reference the *EUA*, *ibid*, s 117. Nevertheless one generally thinks of a rule as something which establishes a norm to be applied across the board to similar situations that fall within a class rather than as a term or condition of approval of a particular application.
195 *EUA*, *ibid*, s 117(2). We are not aware of any case in which the AUC has conditioned an exemption in this way.
196 *Re Nabiye Project*, *supra* note 149 at para 75; *Re Connacher Oil and Gas Limited, Cogeneration Plant and Industrial System Designation Great Divide and Algar Oil Sands Projects* (2 March 2010), 2010-094 at para 53, online: AUC <www.auc.ab.ca/applications/decisions/Decisions/2010/2010-094.pdf>.
197 "Industrial Systems Policy Statement," *supra* note 142 at 4; *NADC Report*, *supra* note 24 at 37.
198 "Industrial Systems Policy Statement," *ibid* at 4.
199 *Re Industrial System*, *supra* note 140 at para 19.
200 *Ibid* at para 24.
201 *Ibid* at paras 19, 84.

*EUA* authorize the AUC to order the owner of an ISD to provide access to transmission lines within an ISD and may set the terms and conditions of such access.[202]

Last, an ISD operator does not have to participate in obligations and entitlements for the exempted electric energy or province-wide transmission tariffs.[203] However, ISDs that have existing contracts with an electric distribution system, or the ISO, must either fulfill or pay-out such contracts.[204]

The above exemptions only apply to the electric energy that is generated and consumed by the industrial system.[205] If the ISD owner needs to receive electricity for use on property, it will still need to deal with the owner of the EDS in whose service area the property is located.[206] Alternatively, the ISD owner may agree with the ISO to receive electrical services directly from the transmission system, but the ISD must obtain approval from the distribution system owner and the AESO in accordance with section 101(2) of the *EUA*.[207] An industrial system that relies on the interconnected electric system to receive support services is not exempted from present or future applicable tariffs.[208]

In addition to the exemptions from certain portions of the *EUA*, an ISD also has some implications for the application of the *HEEA*. The owner of an ISD transmitting or proposing to transmit electric power is exempted from sections 14 and 15 of the *HEEA*, which require permitting and licensing for transmission facilities, unless the AUC directs otherwise.[209] This exemption applies if the ISD owner is transmitting electricity over land of which it is the owner or tenant, or across a public highway dividing land that is owned or leased by it.[210] Similarly, sections 28 and 29 of the *HEEA*, which focus on service areas, do not apply to transmission or distribution facilities within an ISD since these provisions deal with the delivery of electric energy to customers. An ISD "does not have consumers" it "only has transmission facilities for its industrial system."[211]

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202 *Ibid* at para 91. It follows from this that the AUC does not have to address access as part of approving an ISD application, and furthermore, the argument that another TFO might not be able to access the transmission lines with the ISD is not a reason for excluding the proposed transmission lines from the ISD. See Part VI.B, above, and especially *supra* note 119.

203 "Industrial Systems Policy Statement," *supra* note 142 at 4. The costs and benefits of Alberta's existing regulated utility generating units are shared by all customers in the province. The mechanism for achieving this objective is a set of legislated financial hedges between distributors and owners of existing generating units.

204 *Ibid*.

205 *Re Cold Lake*, *supra* note 119 at 11.

206 See discussion in Parts VI.B and VI.C, above; *EUA*, *supra* note 59, s 101; *Rule 007*, *supra* note 109 at 5.

207 *EUA*, *ibid*, s 101, means that oil sands developers must arrange for distribution service from the distribution system owner in the area (ATCO Electric and FortisAlberta are the distribution owners in the oil sands areas). When assessing a project for section 101 approval, it is generally preferred that a site have an ISD order from the AUC. Failure to obtain section 101 approval and an ISD order can have a detrimental impact on cogeneration development: *OSCA 2014*, *supra* note 40 at 17.

208 *Re Cold Lake*, *supra* note 119 at 11.

209 *Supra* note 13, s 16(1)(b). But see discussion in EUB Decision D99-4, *ibid*. Note however, that as a matter of practice, the AUC frequently requires an owner to apply under sections 14 and 15 as a term or condition of an ISD – which is evidently the AUC "otherwise directing."

210 *HEEA*, *ibid*; see also *Re EnCana*, *supra* note 190 at paras 13–15, emphasizing that while this provision applies specifically to transmission facilities, an ISD owner has a general right to construct and operate both transmission and distribution facilities within its own designated area without further approvals.

211 *Re Industrial System*, *supra* note 140 at para 20.

## VII. THE TREATMENT OF COGENERATION UNDER ALBERTA'S GREENHOUSE GAS MANAGEMENT REGIME

It is evident from Part VI.E that cogeneration projects may qualify for an industrial system designation order under the *HEEA*[212] and that such a designation will confer a number of regulatory benefits. This part of the article deals with the treatment of cogeneration under the 2007 *Specified Gas Emitters Regulation*,[213] which was enacted under Alberta's *Climate Change and Emissions Management Act*.[214] Part VII.A provides a general account of the *SGER* and Part VII.B explains the treatment of cogeneration under the *SGER*.

### A. SPECIFIED GAS EMITTERS REGULATION

The *SGER* imposes greenhouse gas emission intensity reduction requirements on regulated facilities, which are facilities that emit 100,000 tonnes or more of direct emissions (carbon dioxide equivalent ($CO_2e$)) annually.[215] A "facility" is broadly defined and includes a plant, structure, or thing and refers to activities listed in the *Environmental Protection and Enhancement Act*.[216] In determining whether a facility is subject to the *SGER*, all of the facility's on-site greenhouse gas emissions must be included in its direct emissions.[217] Thus, a mining or *in situ* oil sands facility might include within its boundaries a cogeneration facility.

Regulated facilities must establish a baseline emissions intensity based on the ratio of total annual emissions to production for the appropriate years of commercial operation of the facility. The *SGER* requires regulated facilities to reduce their annual emissions intensity by up to 12 percent below their baseline emission intensity depending on whether the facility is an "established facility" or "new facility."[218] In general, a new facility is a facility that has completed less than eight years of commercial operation, whereas an established facility has completed eight or more years of commercial operation.[219]

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212 *Supra* note 13.

213 Alta Reg 139/2007 [*SGER*]. The *SGER* was originally scheduled to sunset on 30 September 2014 but was successively extended by the then-Progressive Conservative administration to 31 December 2014, and again to 30 June 2015. On 25 June 2015, the incoming New Democratic Party administratation announced that it would further extend the *SGER* to 31 December 2017 pending a more comprehensive review. At the same time, the government also announced that it would change two of the key variables in the *SGER*, specifically (1) the emissions intensity reduction target would be increased from 12 to 15 percent in 2016 and to 20 percent by 2017; and (2) the compliance price would be increased from $15 a tonne in 2015 to $20 in 2016 and $30 in 2017. See Government of Alberta, "Province takes meaningful steps toward climate change strategy" (25 June 2015), online: Government of Alberta <www.alberta.ca/release.cfm?xID=38232B11A8C17-0B34-BB8E-6B03088 D90D1C786>. On 25 June 2015, the *Specified Gas Emitters Amendment Regulation*, Alta Reg 104/2015, came into force. In addition to increasing the emissions intensity reduction target, as described above, this regulation, among other things, deals with the treatment of cogeneration. In particular, this regulation amends the *SGER* by adding a "cogeneration compliance adjustment" (CCA), which will be defined in the "Standard for Completing Greenhouse Gas Compliance Reports." See note 244 below.

214 SA 2003, c C-16.7 [*CCEMA*].

215 *SGER*, *supra* note 213, s 2. A greenhouse gas reporting regulation, the *Specified Gas Reporting Regulation*, Alta Reg 251/2004, came into force in 2004 and currently requires facilities with annual emissions of 50,000 tonnes $CO_2e$ or more to file a verified emissions report. In 2011, the threshold was reduced from 100,000 $CO_2e$/year or more.

216 *SGER*, *ibid*, s 1(j); *Environmental Protection and Enhancement Act*, RSA 2000, c E-12.

217 The *SGER*, *ibid*, s 1(l)(e), defines "direct emissions" as the release of specified gases "from sources located at a facility," expressed in tonnes on a $CO_2e$ basis. A Schedule of specified gases is included in the *SGER*.

218 Changing to 15 percent in 2016 and 20 percent in 2017, see note 213, *supra*.

219 *SGER*, *supra* note 213, ss 1(1)(i), (p).

Emissions intensity reduction obligations for new facilities are phased-in over a six-year period at a rate of 2 percent per year beginning in the fourth year of commercial operation. For the first three full years of its commercial operations, a new facility is under no regulatory obligation to reduce its emissions intensity. Its fourth year of commercial operation is the first year when an enforceable requirement of emissions reduction is imposed. If a new facility has been in commercial operation for more than four years, a continuous improvement of 2 percent from its baseline emission intensity will be imposed for each year until the facility becomes an established facility. A new facility becomes an established facility after completing eight years of commercial operation. An established facility must reduce its emissions intensity by 12 percent below its baseline emission intensity.[220]

### 1. BASELINE EMISSIONS INTENSITY

The required reduction of annual emissions intensity under the *SGER* is based on a facility's baseline emissions intensity (BEI). The BEI is the ratio of total annual emissions to production in the baseline years.[221] A facility's BEI is based on its total annual emissions in the appropriate years. For a new facility the BEI is calculated based on a "rolling three year baseline," which starts in a facility's third year of commercial operation,[222] as follows:

| Year | Baseline Emissions Intensity |
|---|---|
| Start-up | No Baseline |
| Year 1 | No Baseline |
| Year 2 | No Baseline |
| Year 3 | No Baseline |
| Year 4 | Year 3 |
| Year 5 | Years 3 and 4 |
| Years 6 to 9 | Years 3, 4 and 5 |

The *SGER* provides Alberta Environment and Sustainable Resource Development (ESRD) broad discretion to determine[223] and establish a BEI.[224] ESRD also has broad discretion to establish a new BEI and in this regard may at any time review the BEI for a facility and establish a new BEI or direct the facility to apply for a new BEI where ESRD is of the view that (1) the BEI is inaccurate; (2) the facility has undergone an expansion or significantly changed; or (3) for any other reason a revised BEI is appropriate.[225]

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220 Changing to 15 percent in 2016 and 20 percent in 2017, see note 213, *supra*.

221 *SGER*, *supra* note 213, s 21.

222 Alberta Environment and Sustainable Resource Development, *Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications*, Version 4.0 (Edmonton: AESRD, Development, July 2012) at 38, online: Government of Alberta <open.alberta.ca/dataset/cf65e026-174b-48c7-9bb5-a1811d2781a0/resource/d1012881-d5a8-4547-a77e-640daac28c99/download/5674251-2012-Technical-Guidance-Completing-Specified-Gas.pdf> [*Baseline Guidance*].

223 *SGER*, *supra* note 213, s 21(2)(b).

224 *Ibid*, s 22.

225 *Ibid*, s 23.

## 2. NET EMISSIONS INTENSITY

Each year, a regulated facility must calculate its net emissions intensity (NEI). The *SGER* measures "emissions intensity" by the quantity of specified gases released by a facility per unit of production from that facility.[226] NEI for a facility is calculated annually using the following formula:

$$NEI = \frac{(TAE - (EO+FC+EPC))}{P}$$

Where: NEI is net emissions intensity for the facility;
TAE is total annual emissions from the facility;
EO is allowable emission offsets;
FC is allowable fund credits;
EPC is allowable emission performance credits;
P is production for the year.[227]

## 3. NET EMISSIONS INTENSITY LIMITS

Once a regulated facility has determined its BEI, the *SGER* requires the facility to reduce its annual emissions intensity such that the NEI for the facility must not exceed the facility's BEI as follows:

(i) 88 percent of the baseline emissions intensity for an established facility; and

(ii) For a new facility:
   a. 98 percent of the baseline emissions intensity in the 4th year of commercial operation;
   b. 96 percent of the baseline emissions intensity in the 5th year of commercial operation;
   c. 94 percent of the baseline emissions intensity in the 6th year of commercial operation;

226 *Ibid*, s 1(1)(h).
227 *Ibid*, s 6(1).

d. 92 percent of the baseline emissions intensity in the 7th year of commercial operation;
e. 90 percent of the baseline emissions intensity in the 8th year of commercial operation.[228]

Once a new facility has completed eight years of commercial operation, it will be considered an established facility and subject to a NEI limit of 88 percent of its BEI in the ninth year of commercial operation and future years.[229]

4. OFFSETS AND CREDITS

If a facility cannot meet its reduction obligation (the facility is exceeding its NEI limits) by implementing facility improvements (for example, technology improvements), the following three compliance options are available under the *SGER*: (1) emission offsets; (2) fund credits; and (3) emission performance credits.[230] Use of these compliance options must accord with any relevant Ministerial guidelines.[231]

Emission offsets are generated through reductions of specified gases resulting from activities not regulated by the *SGER* or otherwise required by law.[232] The *SGER* provides that an emission offset can be generated by a reduction in non-regulated facilities in the release of specified gases, a geological sequestration of specified gases, or a capture of specified gases that are geologically sequestered. In order for the reduction to qualify as an emission offset the reduction must: (1) occur in Alberta; (2) be the result of an action taken that is not otherwise required by law; (3) occur and be the result of actions taken on or after 1 January 2002; (4) be real and demonstrable; and (5) be quantifiable and measurable.[233] There are additional, and somewhat different, criteria respecting emission offsets for a geological sequestration of specified gases or a capture of specified gases that are geologically sequestered.[234] ESRD also requires that offset projects are: (1) implemented according to the ESRD approved quantification protocol; (2) verified by a qualified third party auditor;[235] and (3) registered in the Alberta Emissions Offset Registry.[236]

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228 *Ibid*, s 4(1).
229 Net emission intensity limits in addition to or in substitution of those set out in *SGER*, *ibid*, s 4(1) may be established by Ministerial Order (*ibid*, s 4(4)). There is a duty to comply with the relevant net emissions intensity limits (*ibid*, s 6(2)).
230 *Ibid*, ss 7–9. Emissions offsets, fund credits, and emission performance credits are "revocable licences," and nothing in the *SGER* "ensures or guarantees the availability of emissions offsets or emission performance credits" (*ibid*, s 10).
231 *SGER*, *ibid*, ss 7(2)(d), 8(3)(e), 9(2)(e). *CCEMA*, *supra* note 214, ss 61–62 provide that the *SGER* may adopt or incorporate by reference guidance documents.
232 *SGER*, *ibid*, ss 1(1)(f), 7. See also Alberta Environment and Sustainable Resource Development, *Technical Guidance for Completing Specified Gas Compliance Reports*, Version 7.0, (Edmonton: AESRD, January 2014) at 34–36, online: Government of Alberta <esrd.alberta.ca/climate-change/guidelines-legislation/specified-gas-emitters-regulation/documents/TechGuidanceCompletingSpecGasComplianceRpts-Feb2014.pdf> [*Compliance Guidance*].
233 *SGER*, *ibid*, s 7(1); *Compliance Guidance*, *ibid* at 34. As of 1 January 2012, new offset projects are only eligible to generate offset credits on a go-forward basis (Alberta Environment and Sustainable Resource Development, *Technical Guidance for Offset Project Developers*, Version 4.0 (Edmonton: AESRD, February 2013) at ss 3.3.4–3.3.5, online: Government of Alberta <environment.gov.ab.ca/info/library/8525.pdf>).
234 *SGER*, *ibid*, ss 7(1.1), (1.2).
235 *Ibid*, s 18.
236 *Compliance Guidance*, *supra* note 232 at 34.

Fund credits can be obtained by contributing money to the Climate Change and Emissions Management Fund established under the *CCEMA*.[237] The cost of a fund credit is currently (2015) $15 per tonne of $CO_2$e as it has been since inception, but this will change to $20 per tonne in 2016 and $30 per tonne in 2017.[238] Fund credits must be obtained on or before the compliance deadlines for each year, cannot be used in future years or traded, and can only be used once.[239]

When a regulated facility achieves actual emissions intensity that is less than the applicable NEI limit for that period (when the facility reduces its specified gas emissions beyond its reduction obligation), the reduction in specified gas emissions not used in meeting the NEI limit results in an emission performance credit (EPC).[240] EPCs must be the result of improvements at a regulated facility, and not be the result of changes in reporting, shifting of emissions, or short-term fluctuations in facility production.[241] Facilities must request an EPC and must describe the actions taken to improve emissions intensity. ESRD reviews requests for EPCs and, if approved, issues serial numbers for the credits.[242] EPCs can be banked (used in future compliance years) or traded to another facility and can only be used once.[243]

## B. TREATMENT OF COGENERATION UNDER THE *SGER*[244]

The *SGER* contains no specific mention of cogeneration. However, cogeneration is dealt with in the relevant ESRD guidance documents including: (1) *Technical Guidance for Completing Specified Gas Baseline Emission Intensity Applications*, Version 4.0, July 2012[245]; and (2) *Technical Guidance for Completing Specified Gas Compliance Reports*, Version 7.0, January 2014.[246] These ESRD guidance documents are not themselves incorporated by reference into the *SGER* except to the extent the *SGER* provides that any use of compliance options to meet the requirements of the *SGER* must accord with any relevant Ministerial guidelines.[247]

The ESRD guidance on cogeneration recognizes the environmental benefits associated with the higher energy efficiencies of cogeneration operations and the low emission intensity production of electricity.[248] Further, the ESRD guidance acknowledges that "[c]ombined use

237 *SGER*, *supra* note 213, ss 1(1)(k), 8(1); *CCEMA*, *supra* note 214, s 10.
238 The cost of fund credits is established by Ministerial Order (*SGER*, *ibid*, s 8(2)). On the changes, see *supra* note 213.
239 *SGER*, *ibid*, s 8(3); *Compliance Guidance*, *supra* note 232 at 36.
240 *SGER*, *ibid*, ss 1(1)(g), 9(1); *Compliance Guidance*, *ibid* at 32–33.
241 *Compliance Guidance*, *ibid* at 32.
242 *Ibid* at 32–33.
243 *SGER*, *supra* note 213, s 9(2).
244 On 25 June 2015, the *Specified Gas Emitters Amendment Regulation*, *supra* note 213, came into force. This regulation, among other things, amends the *SGER*, *ibid*, by adding a "cogeneration compliance adjustment" or CCA, which will be defined in the "Standard for Completing Greenhouse Gas Compliance Reports." Notably, section 6(1) of the *SGER*, as amended, requires that the net emissions intensity for a facility for a year must be determined by deducting the CCA. Further, section 9(1.1) of the *SGER*, as amended, requires that the CCA be deducted when determining the maximum amount of EPCs for a facility for a year.
245 *Supra* note 222.
246 *Supra* note 232.
247 *SGER*, *supra* note 213, ss 7(2)(d), 8(3)(e), 9(2)(e). *CCEMA*, *supra* note 214, ss 61–62 provide that the *SGER* may adopt or incorporate by reference guidance documents.
248 *Baseline Guidance*, *supra* note 222 at 42–46.

of heat in production and to generate electricity improves the overall efficiency of the plant and can displace higher emitting coal-generated electricity."[249] It is uncertain exactly which electrical generating units (coal, combined cycle natural gas, or simple cycle natural gas) are being displaced by cogeneration at any one point in time.[250] However, oil sands facilities with integrated cogeneration generally do not respond to power prices[251] and typically bid $0 into the Alberta Power Pool to ensure dispatch (see further discussion in Part V.A, above). Therefore, such facilities provide reliable, low cost, low emissions intensity base load electricity to the Alberta power grid.

As a result of the environmental benefits of cogeneration, the *SGER* treats cogeneration differently when determining the BEI and calculating the NEI each year for both stand-alone and integrated cogeneration facilities.[252] Further, cogeneration facilites may generate credits for a facility owner by allowing the owner to claim EPCs for the difference between deemed electricity emissions and actual electricity emissions. Deemed electricity emissions are calculated on the basis that the facility owner operates a stand-alone combined cycle gas turbine facility to produce electricity. Since the owner is actually operating a cogeneration facility with the efficiencies described in Part II of this article, the owner's actual electricity emissions will be significantly below its deemed electricity emissions. For cogeneration facilities, the details of how the BEI is determined and NEI is calculated as well as the details of the crediting procedure for EPCs are described below.

### 1. BASELINE EMISSIONS INTENSITY FOR FACILITIES WITH COGENERATION

The BEI for facilities with cogeneration is determined by including only cogeneration emissions that are deemed to have been necessary for heat generation.[253] Deemed emissions from electricity generation are exempt when determining the BEI for facilities with cogeneration.[254] The BEI calculation assumes that, during the baseline period, the heat was sourced from a conventional boiler operating at an efficiency of 80 percent and the electricity was produced from a natural gas combined cycle electricity generator with a greenhouse gas intensity of 0.418 tonnes $CO_2e$/MWh.[255]

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249 *Ibid* at 42; *Compliance Guidance*, *supra* note 232 at 56.

250 See Doluweera et al, *supra* note 50 at 7968.

251 Oil sands facilities with cogeneration generally are not price sensitive because electricity sales represent a small portion of revenues and the priority is often to meet the constant thermal energy demand.

252 "Stand-alone" cogeneration facilities derive all their energy outputs from on-site fuel combustion (there are no other external energy inputs). All emissions from a stand-alone facility are from cogeneration related equipment. "Integrated" cogeneration facilities, in addition to their own fuel source, also have other fuel sources contributing to generating heat and electrical output (*Baseline Guidance*, *supra* note 222 at 42; *Compliance Guidance*, *supra* note 232 at 52.).

253 Deemed greenhouse gas emissions from heat generation are calculated according to the methodology outlined in sections 6.4.1 and 6.4.2 of the *Baseline Guidance*, *ibid* at 43–45.

254 Deemed greenhouse gas emissions from electricity generation are calculated according to the methodology outlined in sections 6.4.3 and 6.4.4 of the *Baseline Guidance*, *ibid* at 45–46.

255 *Ibid* at 42.

The following formula is used to calculate the BEI for a facility with integrated cogeneration:

$$BEI = \frac{(TAE - G_T) + D_H}{P}$$

Where: BEI is baseline emission intensity;
TAE is total annual greenhouse gas emissions from the entire facility for each baseline year;
$G_T$ is total annual greenhouse gas emissions from cogeneration for each baseline year;
$D_H$ is deemed greenhouse gas emissions from heat production for each baseline year;
P is production for each baseline year.[256]

For example, to calculate the BEI for an *in situ* oil sands facility with integrated cogeneration, the total annual emissions from the entire facility (TAE) includes emissions from cogeneration ($G_T$) and other emissions from the production of oil sands (for example, emissions from the central processing facility and the well pads). Given the environmental benefits of cogeneration, only cogeneration emissions that are deemed to have been necessary for heat production ($D_H$) are included in the BEI. In other words, deemed emissions from electricity generation are not included in the BEI. To calculate the BEI without including deemed emissions from electricity generation, the emissions from cogeneration ($G_T$) are subtracted from the total annual emissions from the entire facility (TAE) and then the deemed emissions from heat production ($D_H$) are added. An *in situ* oil sands facility with integrated cogeneration produces two products — oil sands and electricity; however, because deemed emissions from electricity are not included in the BEI, the production (P) is generally bitumen[257] in the formula above.

For a new facility with stand-alone cogeneration, the deemed greenhouse gas emissions attributed to heat production for each baseline year ($D_H$) is divided by the total heat produced by the cogeneration facility during the baseline year. Therefore, the total heat produced by the cogeneration facility during the baseline year is P and TAE equals $G_T$ in the formula above.[258]

Under the *SGER*, ESRD has broad discretion to determine and establish a BEI.[259] ESRD also has broad discretion to establish a new BEI, among other things, in cases where the facility has undergone an expansion.[260] The ESRD guidance deals specifically with phased expansions, including phased expansions of *in situ* oil sands facilities[261]and including such

256 *Ibid* at 37, 46.
257 Each facility must determine an appropriate production metric during the establishment of its BEI. Facilities producing multiple products must report the individual products and convert such products into a single denominator. For example, an *in situ* oil sands facility whose product is diluted bitumen must report the quantity of diluent and bitumen included in the denominator and the conversion factor used to obtain common units (*Compliance Guidance*, *supra* note 232 at 53).
258 *Baseline Guidance*, *supra* note 222 at 46.
259 *Supra* note 213, ss 21(2)(b), 22.
260 *Ibid*, s 23.
261 *Baseline Guidance*, *supra* note 222 at 18, 38–41; *Compliance Guidance*, *supra* note 232 at 23–27.

facilities with cogeneration.[262] In short, ESRD must decide if an expansion to an existing *in situ* oil sands facility is a phased expansion or a new facility.[263] To be eligible for phased expansion treatment, which includes a separate expansion phase BEI and expansion phase compliance period, an *in situ* oil sands facility must meet certain criteria in the ESRD guidelines.[264] If all of the criteria are not satisfied, the whole facility, including the expansion, must comply with the existing BEI.[265]

### 2. NET EMISSIONS INTENSITY FOR FACILITIES WITH COGENERATION

The NEI for facilities with cogeneration is calculated each year in a manner similar to the NEI for facilities without cogeneration.[266] That is, the NEI is computed by subtracting all offsets and credits.[267] The NEI calculations differ between integrated and stand-alone cogeneration facilities, however, in both cases deemed emissions from electricity generation are excluded. As a result there is no reduction obligation for emissions associated with electricity generation.[268] The emissions intensity for facilities with cogeneration is calculated for the compliance year by subtracting the deemed emissions attributed to electricity generation from the total annual emissions and then dividing that by the production during the compliance year.[269]

Deemed emissions from electricity generation are calculated by multiplying the total electricity generated by the cogeneration facility by the emissions intensity of a natural gas combined cycle turbine, which is deemed to be 0.418 tonnes $CO_2$e/MWh.[270]

### 3. FACILITIES WITH COGENERATION MAY EARN EMISSION PERFORMANCE CREDITS

In order to recognize the environmental benefits associated with the higher energy efficiencies of cogeneration operations and the low emission intensity production of electricity, facilities with cogeneration may earn EPCs.[271] EPCs will be issued where the emissions intensity for electricity generated from the cogeneration facility is less than the

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262 Phased expansion treatment for *in situ* oil sands facilities is used because "[d]uring expansion start up in the *in situ* oil sands sector, there is typically a period lasting up to one year where the expansion phase experiences significant emissions with little or no production, creating a high emissions intensity relative to ongoing operations" (*Compliance Guidance*, *ibid* at 24).

263 *Ibid* at 24–27.

264 The criteria are: (1) a significant change in emissions (25 percent increase) associated with the addition of steam generation; (2) the overall facility's emissions intensity has been affected by the expansion by more than 10 percent compared to the BEI; and (3) a clear and accurate method for separating both the emissions and production between the expansion phase and the existing facility (*Baseline Guidance*, *supra* note 222 at 38–39; *Compliance Guidance*, *ibid* at 25).

265 *Baseline Guidance*, *ibid*; *Compliance Guidance*, *ibid*.

266 *SGER*, *supra* note 213, s 6(1).

267 *Compliance Guidance*, *supra* note 232 at 58–59.

268 *Ibid*, at 58.

269 *Ibid* at 58–59.

270 *Ibid* at 57–58.

271 See Alberta Environment and Sustainable Resource Development, *Specified Gas Emitters Regulation Consolidated Reporting Form*, Version 3.2 (Edmonton: ESRD, 2012) at Section E1 where "Recognition of Cogeneration Efficiency" is calculated, online: Government of Alberta <www.environment.gov.ab.ca/info/library/8436.xls>.

deemed 0.418 tonnes $CO_2$e/MWh and the facility as a whole also achieves its NEI limit for the compliance year.

Some argue that the 0.418 tonnes $CO_2$e/MWh reference used to calculate EPCs provides only limited recognition of the efficiency benefits of cogeneration. The recognition is limited because the Alberta power grid has an emission intensity that is significantly higher than 0.418 tonnes $CO_2$e/MWh. This leads some to take the position that EPCs should be calculated based on the annual average Alberta power grid emission intensity (most recently stated by ESRD to be 0.88 $CO_2$e/MWh) to recognize the grid displacement benefits of cogeneration.[272]

The use of EPCs from cogeneration is an important compliance option under the *SGER* for the oil sands industry. However, there is some uncertainty about the status of EPCs since the *SGER* provides that such credits are revocable and their availability is not guaranteed.[273] Therefore, a facility risks losing such credits at any time.

#### 4. SUMMARY OF THE TREATMENT OF COGENERATION UNDER THE *SGER*

In summary, there are three important elements to the treatment of cogeneration facilities under the *SGER*. First, a cogeneration facility associated with another industrial activity (for example, oil sands mining or an *in situ* operation) may be included within the definition of a regulated facility under the *SGER*. Second, in determining the BEI for a facility with cogeneration, ESRD only includes the cogeneration emissions that are deemed to have been necessary for heat generation. The deemed emissions from electricity generation are not included in the BEI and consequently there is no reduction obligation associated with emissions from electricity generation from the facility. Third, a cogeneration facility may be issued EPCs where the emissions intensity for electricity generated from the cogeneration facility is less than the deemed 0.418 tonnes $CO_2$e/MWh. Some argue that this significantly understates the actual emissions avoided by displacement of existing base load coal generation.

## VIII. CONCLUSIONS

Cogeneration is an important part of Alberta's electricity mix and its importance is likely to grow for two reasons. First, oil sands projects will continue to need process heat and electricity as part of their extraction, processing, and upgrading. These requirements can be most efficiently met by on-site cogeneration facilities which provide stream and electricity for the operation. Second, the efficiencies associated with cogeneration mean that there are also greenhouse gas mitigation advantages associated with this technology, especially when compared with stand-alone carbon-based generating facilities. It is therefore appropriate to understand how government regulates, and how government incents, new cogeneration projects. That is the inquiry we have conducted in this article. The inquiry is not straightforward for at least three reasons.

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272 See Memorandum from Bob Savage (20 December 2011) "Notice of Change for Emission Factor for Increased Grid Electricity Usage," online: Alberta Environment and Parks <www.environment.gov.ab.ca/info/library/8429.pdf>.

273 *SGER*, *supra* note 213, s 10.

First, the government does not regulate cogeneration projects as a separate legal category. Instead, a cogeneration facility is a participant in Alberta's energy market much like any other player. Thus, construction of such a facility is not subject to an economic needs analysis and the owner of the facility will be able to bid surplus power into the Power Pool in common with other generators. Similarly, as with all new generation, the physical construction of the facility does require regulatory approval under the *HEEA*.

Second, cogeneration is a form of self-generation. The cogenerator seeks to consume its own power "behind the fence." But a cogenerator also seeks access to the grid, both to "export" surplus power and perhaps to "import" power, either to cover a deficiency or to accommodate a shut-down of its own facilities. This means that a cogenerator inevitably has to deal with the web of provisions under the *HEEA* which address connection to the grid and transmission, and perhaps also distribution and relations with distribution system operators as well as the AESO. Some exemptions from the standard *HEEA* requirements are available to a cogeneration facility if that facility can obtain a designation from the AUC as an industrial system; the main advantages of an industrial system designation are summarized at the end of Part VI. Other exemptions are available under the *EUA* to any self-generator, but the scheme is complex and far from transparent. It should be possible to simplify these provisions and address potential inconsistencies between the provisions of the *EUA* and *HEEA* especially with respect to the role of distribution system owners.

Third, cogeneration may be attractive to the operator of a large industrial facility because of the treatment of cogeneration under the *SGER*. Once again, the incentives are far from transparent because neither the *SGER*, nor its authorizing statute, specifically refers to cogeneration. The main incentives for cogeneration under the *SGER* are summarized at the end of Part VII.

Finally, we observe that Alberta does not have a coherent cogeneration policy. Instead, the province has a de facto position on cogeneration created by the interaction of a number of different policy documents and statutes including the Industrial Systems Policy Statement (1997), the Transmission Development Policy (2003), the *EUA*, the *HEEA*, the *Transmission Regulation* and the *SGER*, and guidance documents designed to implement the *SGER*. Given the scale and importance of cogeneration to the province's industrial sector, and indeed to the province generally, it is time that Alberta developed a clear and coherent policy on cogeneration.